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IMPACT OF STEAM ADDITIVES ON THE PRODUCTIVITY OF THE CYCLIC STEAM STIMULATION PROCESS

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EXECUTIVE SUMMARY

The objective of this study is to determine if the use of steam additives during the cyclic steaming process of heavy oil wells at Pelican Lake Project is effective in increasing the oil production and in obtaining a better understanding of the various process mechanisms which affect heavy oil recovery.

Steam generators are used industry-wide during cyclic steaming operations and are generally controlled to produce approximately 80% quality steam for injection. Effluents from this type of steam generator often have pH values above 12 due to the use of high bicarbonate waters as feeds. The normal practice is to inject the entire alkaline boiler effluent into the reservoir.

The effects of alkalinity and steam additives on interfacial tension and oil recovery have been evaluated in various laboratory tests but it is almost impossible to recreate the changing reservoir conditions induced by alkaline steam injection. This study endeavors to examine the role and potential of steam additives as well as the effects of the standard boiler effluents during cyclic steaming and thereby provide a basis for optimization of this process.

The specific areas of study are as follows:

(i) Determination of changes in production as a result of steam additives.

(ii) Determination of interfacial tension of produced and injected fluids with and without additives.

(iii) Determination of the effect of steam additives on the emulsion formation tendency of boiler effluents and reservoir water.

(iv) Determination of the impact of alkaline boiler effluent reactions as well as steam additive adsorption or decomposition.

Very little research has been done to optimize the cyclic steam process in recent years. Research efforts have primarily concentrated on fluid/rock interactions and reservoir damage. The few laboratory studies on steam additives were generally not performed under the alkaline conditions and temperatures of steam generator effluents. Consequently, the results cannot be easily extrapolated to field applications. Alkali/crude reactions have been studied at reservoir temperature (alkaline waterflooding), but little data is available on high temperature chemistry. In addition, emulsion studies have concentrated on methods of breaking produced emulsions rather than on minimizing or preventing them. Some research on steam additives at elevated temperatures were carried out by universities and industry's R&D centers but they dealt mainly with steam additives stability.

This field research program has studied steam additives, high temperature alkali/crude reactions, and emulsions under real conditions in order to provide a basis for optimization of the cyclic steam process.

The most important task of the present study was to select an additive. Among the criteria used for selection were the following:

i) Proven track record of oil production during field tests and adequate laboratory data base.

ii) Thermal stability under boiler effluent conditions of 250°C and high alkalinity.

iii) Significant lowering of the interfacial tension of Pelican Lake crude and formation water.

iv) Compatability with the carbonate and hydroxide ions in the boiler effluent (i.e., no additive loss by precipitation).

v) Compatability with the reservoir water (i.e., no additive loss by precipitation).

vi) Low adsorption onto the reservoir rock.

vii) Low losses into the hydrocarbon phase while still having the ability to lower interfacial tension.

viii) No adverse effect on the viscosity of emulsions formed during the production phase.

Suntech IV FA and Shell's ENORDET LTS 18 were selected for laboratory screening before the Pelican Lake field trial. Suntech IV FA is similar to Suntech IV except for the addition of an alkaline silicate. Suntech IV is an alkyl toluene sulfonate wherein the alkyl group is a mixture of C_{14} to C_{18} side chains having an average 16 carbon atoms. Suntech IV is a mixture of 60% m-alkyltoluene sulfonate and 40% p-alkyltoluene sulfonate. Shell's ENORDET LTS 18 is quite similar structurally to Suntech IV and is produced by the alkylation of toluene with various linear olefins.

Tables 2-8 provide the compatability of the two additives with Pelican Lake reservoir water and boiler condensate at various temperatures as well as the evolution of the interfacial tension of Pelican Lake crude versus temperature in the presence of the additives. Based on the criteria mentioned before, the additive chosen for use in the study was Suntech IV FA. The additive is sold as a 35% active solution.

The next major task of the study was to select the wells for the field trial. A group of 18 primary production wells drilled in 1986 were examined to select the candidates. Ten of the wells are located north of the pilot area on twenty acre/well spacing in an area which has been designed for purposes of this study as "Area I". The remaining eight wells are located south of the pilot area on 15-20 acre/well spacing in an area designated as "Area II". The eight wells (please refer to paragraph B.1.3) were divided into four well pairs. Each well pair selection was made in order to pair similar wells together, based on comprehensive geological, reservoir and production data. The well pairing was necessary in order to provide a consistent test base so that production responses between wells could be compared.

Samples procedures and schedules were set up and tailored to expected process phases during steaming and production periods. Attachment 1 indicates the sampling procedure and schedule for a typical study well. For each well, produced fluid (oil and water) samples were being taken initially during the primary production phase (pre-steam). During the steaming period, samples of both steam generator, source water and boiler effluent (condensate) were taken, as well as any pre-flush/workover fluids. More frequent produced fluid sampling took place for the initial high water cut flowback period, when some of the steam additive was expected to be produced back.

The wells were steamed with one well in each well pair being steamed with additive. In all cases, the steaming parameters remained consistent with regard to injection rate, volume and feed water composition. Additive injection procedures were also consistent between all additive wells.

After steaming was complete the wells were returned to production. Both oil and water production data were recorded on a daily basis from each well. This data was compiled and analysed over the seven month period following each well's return to production after steaming.

The study did not provide, from an oil production performance perspective, any definitive evidence to indicate that the cyclic steam stimulation process is enhanced through the addition of Suntech IV FA chemical. No consistency could be observed in oil production trends between the additive and non additive wells. There was some evidence that the additive may be more effective in a higher water cut environment. However, the small test base did not allow any conclusions to be drawn from this observation.

The effect of cyclic steaming with Sun Tech Suntech IV FA on water production appears quite pronounced. Water production from the additive wells exceeded area averages in all cases by amounts varying from 16 - 60%.

Analysis of the laboratory and field tests involved in this study into the effect of steam additives on the optimization of the cyclic steam process of heavy oil wells yielded the following conclusions and recommendations:

- Analysis of the production data did not provide conclusive evidence to indicate that the cyclic steam stimulation process is enhanced through the addition of the Suntech IV FA steam additive. Oil production from the additive wells ranged from 16% below average to 12% above average for the seven month period following stimulation.

- Cyclic steam stimulation with Suntech IV FA increased reservoir water production from all additive wells in the study. This increase in water production ranged from 16-60% above area average water production.

- The addition of Suntech IV FA during the cyclic steaming process did not affect injected water recovery. All wells in the study (additive and non-additive) demonstrated injection water recoveries in the range of 12-17% over the 100 day period of production following steaming.

- Recovery of the Suntech IV FA following the cyclic steaming showed a similar trend to that of injected water recovery. Recovery of the additive over the 100 day period of production following steaming showed 9.2 - 11.4% of the injected amount being recovered.

- The study provided some evidence to indicate that Suntech IV FA may be slightly more effective as a steam additive in higher watercut environments. Due to the small test base, however, no firm conclusions could be drawn from this observation.

- Laboratory studies indicated that the alkaline components of the boiler condensate significantly lowered the interfacial tension between the crude and reservoir water.

- Of the two steam additives screened in the laboratory (Suntech IV FA and Shell ENORDET LTS 18), both demonstrated a strong ability to decrease interfacial tension between the crude and reservoir water.

- Laboratory tests indicated that no unusual emulsions would be formed with the reservoir water with the addition of either Suntech IV FA or Shell ENORDET 18.

- Emulsions formed in the laboratory with boiler condensate were created more readily and were more stable than those formed with reservoir water. This was the case both with and without steam additives.

- Laboratory testing showed that both additives screened (Suntech IV FA and Shell ENORDET LTS 18) were compatible with boiler effluent and reservoir water. No precipitates were formed during compatibility testing.

- It is not recommended at this time that Suntech IV FA be used as a cyclic steam additive for the purpose of increasing oil production, especially in areas of low watercuts.

- It is recommended that further testing be done with Suntech IV FA additives on wells with higher watercuts (i.e. subsequent steaming cycles) to confirm or reject speculation that the chemical is more effective in higher watercut environments.

SOMMAIRE EXECUTIF

L'objectif de cette étude est de déterminer si l'usage des additifs de vapeur pour le processus d'injection cyclique de vapeur dans les puits d'huile lourde localisés au Projet du Lac Pelican est efficace pour l'augmentation de la production de pétrole et pour aboutir à une meilleure compréhension de différents mécanismes qui affectent le processus de récupération de l'huile lourde.

Les générateurs de vapeur sont utilisés partout dans l'industrie pour les opération d'injection cyclique de vapeur et, généralement, ils sont réglés pour produire approximativement 80% vapeur de qualité pour injection. Les effluents provenant de ce type de générateur de vapeur ont souvent des valeurs pH qui dépassent 12, à cause de l'utilisation des eaux d'alimentation avec un haut contenu de bicarbonate. Normalement, tout l'effluent alcalin du générateur est injecté dans le réservoir.

Les effets de l'alcalinité et des additifs de vapeur sur la tension interfaciale et sur la récupération du pétrole ont été évalués à l'aide de différents tests de laboratoire, mais il est presque impossible de recréer les conditions toujours changeantes que l'injection de vapeur alcaline induit dans le réservoir. Cette étude a pour but d'examiner le rôle et le potentiel des additifs de vapeur, ainsi que les effets des effluents de générateur standards sur l'injection cyclique de vapeur, en fournissant ainsi une base pour l'optimisation de ce procédé.

Spécifiquement, les domaines abordés par cette étude sont les suivants:

(i) Détermination des changements de production provoqués par les additifs de vapeur.

(ii) Détermination de la tension interfaciale entre les fluides produits et les fluides injectés, avec et sans additifs.

(iii) Détermination de l'effet des additifs de vapeur sur la tendance manifestée par les effluents de générateur et l'eau du réservoir à former une émulsion.

(iv) Détermination de l'impact des réactions de l'effluent alcalin du générateur, ainsi que de l'adsorption ou la décomposition des additifs de vapeur.

Peu de recherches ont été faites pendant les dérnières années pour l'optimisation du procédé d'injection cyclique de vapeur. Les efforts faits dans le domaine de la recherche ont été concentrés sur les interaction fluide/roche et sur les dommages du réservoir. Les rares études de laboratoire sur les additifs de vapeur n'ont pas été, généralement, faites dans les conditions alcalines et les températures des effluents du générateur de vapeur. En conséquence, les résultats ne peuvent pas être aisement extrapolés pour les appliquer aux gisements. Les réactions alcalis/huile brute ont été étudiées aux températures de réservoir (inondation d'eau alcaline), mais il y a peu de données disponibles concernant la chimie à haute température. De plus, les études faites sur les émulsions se sont concentrées plutôt sur les méthodes de séparation d'émulsions produites que sur leur réduction ou prévention. Quelques recherches sur les additifs de vapeur à hautes températures ont été faites en universités ou dans des centres de recherche et développement de l'industrie, mais en s'occupant, principlement de la stabilité des additifs.

Ce programme de recherche en terrain a étudié les additifs de vapeur, les réactions alcalis/huile brute à haute températures et les émulsions en conditions réelles, afin de créer une base pour l'optimisation du procédé d'injection cyclique de vapeur.

La plus impertante tâche de cette étude a été de sélectionner un additif. Parmi les critères de sélection on a eu les suivants:

(i) Attestation vérifiée de la production d'huile pendant les tests faits en terrain et une base de données de laboratoires adéquates.

(ii) Stabilité thermale dans les conditions de l'effluent du générateur, c'est-à-dire 250^{o}C et haute alcalinité.

(iii) La réduction significative de la tension interfaciale entre l'huile brute du Lac Pelican et l'eau de formation.

(iv) Compatibilité avec les ions carbonates et hydroxydes qui se trouvent dans l'effluent du générateur (pas de perte d'additif par précipitation).

(v) Compatibilité avec l'eau du réservoir (pas de perte d'additif par précipitation).

(vi) Adsorption réduite dans la roche de réservoir.

(vii) Pertes réduites dans la phase hydrocarbure, sans perdre la capacité de baisser la tension interfaciale.

(viii) Pas d'effet adverse sur la viscosité des émulsions formées pendant la phase de production.

Les additifs Suntech IV FA et ENORDET LTS 18 de Shell ont été sélectionnés pour les essais de laboratoire, avant d'être testés en terrain, au Lac Pelican. Le Suntech IV FA est similaire au Suntech IV, excepté l'addition d'un silicate alcalin. Suntech IV est un sulphonate d'alcyl toluène, le groupe alcyl étant un mélange de chaînes latérales de C_{14} à C_{18}, ayant en moyenne 16 atomes de carbone. En même temps, c'est un mélange de 60% m-alcyl toluène sulphonate et 40% p-alcyl toluène sulphonate. ENORDET LTS 18 de Shell a une structure très similaire à celle de Suntech IV, parce qu'il est produit par l'alcylation du toluène avec différentes oléfines linéaires.

Les tableaux 2-8 montrent la compatibilité des deux additifs avec l'eau du réservoir du Lac Pelican et avec le condensé du générateur à différentes températures, ainsi que l'évolution de la tension interfaciale de l'huile brute du Lac Pelican avec la température, dans la présence des additifs. Basé sur les critères que nous avons mentionés, l'additif choisi pour étude a été Suntech IV FA. L'additif est vendu commme solution active à 35%.

La tâche majeure suivante de l'étude a été de sélectionner les puits pour les essais faits en terrain. Un groupe de 18 puits de production primaire forés en 1986 ont été examinés pour la sélection. Dix de ces puits se trouvent au nord de la zone pilote, ayant un écartement de vingt acres/puit, dans un endroit qui a été désigné en vue de cette étude comme "Zone I". Le reste des huit puits se trouvent au sud de la zone pilote, ayant un écartement de quinze - vingt acres/puit, dans un endroit désigné comme "Zone II". Les huit puits (voir paragraphe B.1.3.) ont été divisés en quatre paires de puits. Des données comprehensives géologiques, de réservoir et de production ont été prises en considération pour la sélection des puits qui forment des paires de puits similaires. Les paires de puits étaient nécessaires pour fournir une base de test solide, en comparant les changements de production de chaque puit.

L'horaire et les procédures de prélévement des échantillons ont été établis et réglés pour les phases exigées du processus, pendant les périodes d'injection de vapeur et de production. L'annexe 1 montre l'horaire et la procédure de prélévement des échantillons utilisés dans une étude de puit type. Pour chaque puit on a pris d'abord des échantillons de fluide (huile et eau) pendant la phase de production primaire (pré-injection). Pendant la période d'injection de vapeur, on a prélévé des échantillons de vapeur de générateur, eau source et d'effluent de générateur (condensé), ainsi que de tout fluide de pré-injection/intervention. Le prélévement des échantillons de fluide produit a été plus fréquent pendant la période initiale d'éruption, alors que on s'attendait à ce que l'haut contenu d'eau du fluide entraîne une partie de l'additif de vapeur.

Selon notre méthode, un puit dans chaque paire de puits a été injecté avec de l'additif. Dans tous les cas, les paramètres d'injection ont concordé du point de vue du débit et du volume d'injection et de la composition de l'eau d'alimentation. De la même façon, les procédures d'injection de l'additif ont concordé pour tous les puits qui ont reçu de l'additif.

Quand le processus de l'injection de vapeur s'est terminé, les puits ont été rendus à la production. Les données de la production d'huile et d'eau ont été enregistrées chaque jour, pour chaque puit. Ces données ont été notées et analysées pendant les sept mois qui ont suivi le retour en production de chaque puit, après l'injection de vapeur.

L'étude n'a pas fourni de preuve définitive en ce qui concerne la production d'huile qui puisse indiquer que le processus d'injection cyclique de vapeur est amélioré par l'addition du produit chimique Suntech IV FA. Aucune concordence n'a pas été observée entre la production obtenue des puits qui ont reçu de l'additif et ceux qui n'ont pas reçu d'additif. Il a été prouvé que l'additif peut être efficace quand le pourcentage d'eau est plus élevé. La base réduite du test n'a permis, cependant, de ne tirer aucune conclusion de cette observation.

L'effet de l'injection cyclique de vapeur avec Suntech IV FA sur la production d'eau est très prononcé. La production d'eau des puits qui ont reçu de l'additif a dépassé la moyenne de la zone respective par des quantités variant entre 16-60%.

L'analyse des tests faits en laboratoire et le terrain pour cette étude, de l'effet des additifs de vapeur sur l'optimisation du procédé d'injection cyclique de vapeur dans les puits d'huile lourde a conduit aux conclusions et aux récommandations suivantes:

- L'analyse des données de production n'a pas offert de preuves concluantes pour indiquer que le procédé d'injection cyclique de vapeur est amélioré par l'addition de l'additif de vapeur Suntech IV FA. La production d'huile des puits qui ont reçu de l'additif a été de 16% au-dessous de la moyenne à 12% au-dessus de la moyenne pendant la période de sept mois après l'injection.

- L'injection cyclique de vapeur avec Suntech IV FA a augmenté la production d'eau de réservoir de tous les puits qui ont reçu de l'additif comme partie de cette étude. L'augmentation de la production d'eau a été de 16-60% au-dessus de la production moyenne d'eau de la région.

- L'addition de Suntech IV FA pendant le processus d'injection cyclique de vapeur n'a pas affecté la récupération de l'eau injectée. Tous les puits étudiés (avec ou sans additif) ont eu un taux de récupération d'eau d'injection de 12-17% pendant la période de production de 100 jours après l'injection de vapeur.

- La récupération du Suntech IV FA, après l'injection cyclique de vapeur, a été similaire à la récupération de l'eau d'injection. La récupération de l'additif pendant la période de production de 100 jours après l'injection de vapeur a été de 9,2-11,4% de la quantité injectée.

- L'étude a fourni quelques preuves indiquant que Suntech IV FA peut être un peu plus efficace comme additif de vapeur quand le pourcentage d'eau du fluide produit est plus élevé. Pourtant, à cause de la base réduite de test, nous ne sommes pas arrivés à des conclusions fermes basées sur cette observation.

- Les études de laboratoire ont indiqué que les composants alcalins du condensé du générateur ont beaucoup baissé la tension interfaciale entre l'huile lourde et l'eau du réservoir.

- Les additifs de vapeur étudiés en laboratoire (Suntech IV FA et ENORDET LTS 18 de Shell) ont démontré, tous les deux, une capacité prononcé de baisser la tension interfaciale entre l'huile lourde et l'eau du réservoir.

- Les tests de laboratoire ont indiqué qu'aucune émulsion inhabituelle n'allait se former avec l'eau du réservoir par addition soit du Suntech IV FA, soit du ENORDET LTS 18 de Shell.

- Les émulsions formées dans le laboratoire avec le condensé du générateur ont été réalisées plus facilement et ont été plus stables que celles formées avec l'eau du réservoir, avec ou sans additif.

- Les tests de laboratoire ont démontré que les deux additifs étudiés (Suntech IV FA et ENORDET LTS 18 de Shell) sont compatibles avec l'effluent du générateur et l'eau du réservoir. Aucun précipité ne s'est formé pendant les tests de compatibilité.

- Il n'est pas recommandé, pour l'instant, d'utiliser Suntech IV FA comme additif pour l'injection cyclique de vapeur pour augmenter la production d'huile, surtout dans les régions où le pourcentage d'eau est bas.

- Il est recommandé de continuer les tests avec l'additif Suntech IV FA sur les puits qui ont un haut pourcentage d'eau (c'est-à-dire cycles d'injection de vapeur ultérieurs) pour confirmer ou infirmer le fait que ce produit chimique soit plus efficace quand il y a un haut pourcentage d'eau.

A. BACKGROUND

1.0 ALKALINE INTERACTIONS

The majority of recovery processes being field tested utilize injection of high pressure steam, either in stimulation or steam drive mode. The boiler feedwater may be taken from surface or from water source wells. Due to the following high temperature reactions the pH of the water in the steam generator can increase by over 4 units (1).

$$2NaHCO_3 \xrightarrow[\text{Conversion}]{100\%} Na_2CO_3 + CO_2 + H_2O$$

$$Na_2CO_3 + H_2O \longrightarrow 2NaOH + CO_2$$

The alkaline boiler effluent rapidly attacks quartz and aluminum minerals, precipitates calcium and magnesium salts from formation waters and can cause the in situ production of large quantities of amorphous precipitates which stabilize emulsions (1,2). In addition, the high pH boiler effluent can cause clay swelling and large decreases in permeability (1). However, by reacting with certain organic acids present in the crude oil, caustic solutions can generate surfactants (or soaps) in situ, which concentrate at the oil/water interfaces and reduce interfacial tension. This effect has the potential to improve heavy oil recovery if mineral reactions are not major (i.e. low temperature (3)).

The injection of sodium metasilicate during cyclic steam stimulation of several wells in Kern County, California significantly increased oil production (4). Additional oil production of 1000-4000 bbls/steam cycle were obtained when the additive was used. During these field tests a 20.8% solution of sodium metasilicate was continuously added to the steam at a rate of 14.7 gallons/1000 bbls of steam. Prior to steaming, a 2% solution of the additive was used for preflushing and allowed to soak in the wellbore four to six hours before commencing steam injection (4).

According to Mbaba (4), sodium metasilicate reacts with formation rock and some losses do occur but not to the extent of those reported by Dehgani et al (5) for high temperature sodium hydroxide application. Various laboratory studies on caustic steam additives (6,7) have been done but it is difficult to extrapolate laboratory results to the field since boiler condensate already contains high carbonate and hydroxide ion concentrations. While alkaline additives have shown promising results in low temperature waterflooding conditions (3, 8 & 9) they

had little success when applied with steam in laboratory (6,7). Their lack of success appears to be mainly due to excessive reaction with the reservoir rock matrix at steam temperatures. Even at room temperature, significant reaction and alkali consumption was observed (3).

In conventional light oil reservoirs caustic flooding is used to mobilize residual oil after waterflooding to an economic limit. In heavy oil reservoirs primary production is normally very low; approximately 4% with a possible increase to 10% in recovery by conventional waterflooding (10). To improve on these recoveries, caustic flooding is envisaged as a secondary recovery process.

Scott et al (11) found that recovery by caustic flooding of a 1200 cP (Lloyminster) crude increased by 4% and 31%, in comparison with a waterflood, for caustic concentrations of as little as 0.01 and 0.5% respectively. Farouq Ali et al (12), in a laboratory study, found an increase in the recovery of a Lloydminster crude from 32.1% for a waterflood to 60.3% when 2 PV's of caustic solution were injected. They also concluded that a caustic slug of at least 0.25 PV was needed for a significant recovery increase, and that continuous injection was more effective than slug injection. Drauchuk et al (10) reported recovery improvements similar to Farouq Ali for Lloyminster crude displacements by waterfloods containing concentrations greater than 0.1% NaOH.

Caustic flooding is believed to affect additional oil recovery by the following basic mechanisms (13):

(a) Reducing interfacial tension (IFT) between crude oil and water.
(b) Modifying the wettability at the solid-liquid interface.
(c) Emulsification and entrainment.
(d) Emulsification and entrapment.
(e) Solubilization of rigid interfacial films.

While IFT reduction and wettability reversals are the primary mechanisms involved in caustic flooding of light oils, it is thought that the mechanisms of emulsification and removal of interfacial films also contribute to improved recovery in high viscosity oil reservoirs.

Regardless of which of the mechanisms is involved in any one caustic flooding project, the success of caustic flooding relies on a chemical reaction between the caustic solution and the polar components present in the crude. Caustic reactions with organic acids, primarily carboxylic

acids and to a lesser extent carboxyphenols, porphyrins or asphaltenes (14), lead to in situ generation of surfactants or sodium soaps. This results in the formation of emulsions, wettability reversals, and weakening of rigid or viscous interfacial films.

A most widely quoted measure of caustic reactivity with a certain oil is the acid number. An acid number of 0.2 mg KOH/g crude has been quoted by the National Petroleum Council as a minimum for considering alkaline flooding for light oils. Other values have also been proposed (13, 15, 17). Acid numbers for crude oils can range from zero to 6.4 mg KOH/g. While various minimum acid numbers have been suggested, higher acid numbers do not necessarily result in higher oil recoveries. In fact, there appears to be no direct correlation between the acid number of an oil and the magnitude of enhanced recovery (14). There seems to be a widespread agreement, now, that a better indicator of alkaline activity is a measurement of the interfacial tension. But, even the latter is probably strictly useful only as a screening tool (17).

Most alkaline floods have used sodium hydroxide or sodium orthosilicate with concentrations of up to 5 wt.%. Other alkaline additives, which have been tested in the laboratory or used in the field applications, include sodium metasilicate, ammonia and sodium carbonate (14).

Campbell (18) compared the performance of sodium orthosilicate and sodium hydroxide for alkaline waterflooding. He found that in softened water, with no Ca^{++} or Mg^{++} ions present, both alkaline additives exhibit similar reductions in interfacial tension with all the crude samples tested. When unsoftened water was used to prepare alkaline injection solutions for mid-continent crudes, sodium orthosilicate outperformed sodium hydroxide in significantly reducing IFT values, even when NaOH was applied at much higher concentrations. For California crude oils, the effect of both additives, in reducing IFT, was comparable to each other even when unsoftened solutions were used. However, a later study by Campbell (19), for a Wilmington California field, showed significant residual oil recovery from watered-out sand-packs when sodium orthosilicate was used at concentrations of 0.2 to 0.6%. Very low recovery yields were obtained, on the other hand, when sodium hydroxide was used at 0.2% concentration; no further tests were carried out at higher NaOH concentrations.

Jennings et al (20) concluded that caustic flooding at concentrations in the range of 0.05 to 0.5 wt.% NaOH resulted in in situ emulsification of heavy crudes and

significantly improved oil recovery before breakthrough and lower WOR during the flood. IFT's between caustic and crude of substantially less than 0.01 mN/m (dyne/cm) were specified as being required for the success of the process.

It has been observed (10, 16) that formation water composition can have an important effect on IFT and that the presence of sodium chloride reduces the amount of alkaline additive required for a specific reduction in IFT. Calcium and magnesium ions, on the other hand, increase the amount of caustic required. It was, thus, noted (16, 18, 20) that the presence of these ions in the reservoir water can inactivate the naturally occurring surface active acids, reducing the IFT lowering capability of the caustic. It was also noted (20) that certain multivalent ions can precipitate as insoluble hydroxides, carbonates or silicates with the addition of most alkaline additives to field water samples. If properly controlled and located, these precipitates can act as diverting agents to reduce the fingering and channelling and improve the sweep efficiency and oil recovery (14).

Reactivity of alkaline solutions with silica at moderate temperatures is relatively slow and incomplete. Detailed reaction rate studies, e.g. (21), have found that the reaction rate of the process is dependent on temperature, alkali concentration, alkali type, minerals present and available rock surface area. Reactions with certain clay components, in contrast with silica, may be significant. Clays with high ion exchange capacity can significantly enhance caustic consumption. Exchange of sodium, from an alkali, for calcium and magnesium in the clays may result in the formation of precipitates, which may be accompanied with flow diversion, and/or clay swelling. Sodium/hydrogen ion exchange on the other hand, is fast and reversible causing only a lag in the transport of the alkaline slug through the formation.

At present the use of caustic additives at steam temperatures is surrounded with controversy due to the excessive reaction with the reservoir rock. However, it is appropriate to highlight the current theory and views on the mechanisms of alkaline flooding while at the same time realizing that the boiler condensate reacts very rapidly with the reservoir rock due to the high temperature. The summary given in the following is based on the preceding discussion of the literature as well as the major reviews of the subject which appeared over the last several years (13, 14, 22).

- Alkaline chemicals, added to injection water, react with naturally occurring acids in crude oils (particularly high gravity oils) to produce surfactants in situ.

- These surfactants can result in dramatic reduction in oil-water interfacial tension (down to ITF's in the range of 10^{-3} mN/m). Such low ITF's are believed to be directly responsible for mobilizing trapped and residual oil ganglia (this may be easily demonstrated by consideration of typical pressure gradients and capillary pressures).

- The chemical reactions and low interfacial tensions are also believed responsible for the formation of emulsions (water-in-oil and oil-in-water). Emulsification leads to entrainment of very fine oil droplets with the alkaline solution (Emulsification and Entrainment). Emulsification droplets may also become temporarily mobile, but get retrapped in down stream pore throats (Emulsification and Entrapment). This can improve the sweep efficiency by directing the injection fluid towards undisplaced flow channels.

- Changes in wettability may take place due to the adsorption of soap molecules (formed by interfacial reactions) on the reservoir rock. A reversal from oil-wet to water-wet condition can result in favourable mobility changes in the regions where oil is flowing. A reversal from water-wet to oil-wet can provide flow paths for discontinuous residual oil. Within a reservoir, wettability is not generally a discrete-valued function, but spans a continuum between the two extreme conditions (oil-wet and water-wet). Oil recovery improvement from wettability reversals, thus, depends on a number of factors such as the amount of continuous oil present during wettability alteration, fractional flow of oil and water, and oil-water viscosity ratio. Wettability reversal, therefore, depends on the alkaline water-oil interactions, fluid-solid interactions, reservoir characteristics and conditions, and the alkaline water injection schemes.

- Some crude oils form insoluble rigid films at the oil-water interfaces. These films can have an unfavourable effect on oil displacement in heterogeneous porous media. There are suggestions that alkaline additives may play a role in the solubilization of these films, to improve oil recovery.

- Since boiler condensates have high alkalinities and are injected at high temperatures, the reactions these hot alkaline effluents with reservoir minerals, crude, and water are of prime importance in understanding the mechanisms of the cyclic steam stimulation process.

2.0 FOAMING AGENTS

For almost two decades, and until recently, methods of maximizing oil recovery by steam injection have concentrated on the problems of reservoir conformance and poor vertical sweep efficiency. Attempts, thus, have been made to use foaming agents to help in distributing the heat of the injected steam uniformly across the productive intervals of a reservoir (23, 24).

The foam process was apparently first suggested, in connection with waterflooding, by Bon et al in 1958 (25). It has since been extensively investigated (26-34). It was not until the mid 1970's, however, when more attention was directed to studying the foaming agents in connection with steam injection processes, and to evaluating the effectiveness of foams at elevated temperatures (23, 24, 35-39).

Is is believed (40) that possible beneficial effects of foaming additives are derived from three basic mechanisms. First, foam is relatively low-density material which can easily overcome gravitational effects. It can, therefore, act as a diverting agent which reduces the well known gravity override of steam. Secondly, as a blocking agent, foam can be applied to selectively reduce the permeability of high permeability zones in a heterogeneous reservoir. The third mechanism is based on using foam as a mobility control agent. In this mechanism the mobility of injected steam is reduced by the generation of in-situ foam, resulting in an improved displacement efficiency.

In a Midway-Sunset field demonstration (24), a year-long injection of foam with steam resulted in an estimated 30,000 bbl and 50,000 bbl improvement in oil recovery, from the pattern wells and wells outside the pattern respectively. Diversion of steam was believed to have been achieved by three-phase flow and some foam type of activity. It was also suggested that a viscosity increase, in the flowing-steam phase, resulted in enhancing the volumetric conformance. The dominant effect, however, was attributed to a chemical-additive-augmented steam drive in which oil recovery is enhanced by improved emulsification, lowered interfacial tension, and entrainment of the oil in the flowing steam and hot-water phase.

Presently, the effect of foam plugging in enhancing oil production appears to be highly controversial (41). It is argued that laboratory results which predict the performance of foam with steam, e.g. (42), are irrelevant to reservoir conditions. Some field results which show significant increase in oil production (42) are also discounted (41), on the grounds of being a continuation of a trend that was initiated months before the injection of

steam. Furthermore, doubt has also been cast (41) on the in-situ formation of foams in the presence of steam. This is based on the fact that the foam process requires the presence of a very high liquid volume fraction (5×10^{-2}) to cause maximum pressure increase. At 5% quality 200 pound steam has a liquid volume fraction of only 5×10^{-4}, which would not be sufficient to form effective foam.

3.0 INTERFACIALLY ACTIVE AGENTS

With the controversy surrounding the application of foaming agents and alkaline solutions, as steam additives, increasingly more attention is being directed to the use of other interfacially active agents. There are a vast number of chemicals which have been suggested, and belong to this category. In this group, we include substances which share with alkalis and foams the fact that their function is based on interfacial activity. The mechanisms involved, however, are distinctly different.

In contrast with alkalis, there is no in-situ generation of surfactants. Also, unlike alkaline additives, which are known to undergo vigorous chemical reactions with the reservoir rock, these substances have low reactivity with the rock. In fact, there is evidence that the reactivity of some of these materials, decreases at higher temperatures (43, 44). Furthermore, unlike the foaming agents, the blocking and mobility control properties, of most chemicals under this category, are largely insignificant.

The main function of this category of interfacially active steam additives is to enhance the displacement efficiency from the hot water zone. One or more of a variety of mechanisms is supposed to play a role in the efficiency improvement. These mechanisms include oil-water interfacial tension reduction, water-in-oil emulsion destabilization, emulsification and entrainment of oil, favourable wettability changes, and reduction of the viscosity of the oil-water interfacial layer.

Among the additives of current interest to heavy oil recovery are petroleum sulfonates, alpha olefin sulfonates, and synthetic alkylaryl sulfonates. Petroleum sulfonates have been shown, in laboratory displacement tests, to substantially improve oil recovery and reduce residual bitumen saturations (45). Some concern over the thermal degradation of petroleum sulfonates and their loss during laboratory displacements was expressed in that study. Another study (46) predicted the improvement in steamflood oil recovery, due to the application of sulfonate additives, to reach about 8 to 32% for a Kern River-type reservoir. In the latter study, it was also demonstrated that the alpha olefin and synthetic alkylaryl sulfonates exhibit sufficient thermal stability to enable their use as steam additives. Comparative evaluation of a number of steam additives (46) gave further evidence of the superiority of sulfonate additives for bitumen recovery.

Several recent publications and patents (47-54) deal with a special class of interfacially active steam additives, termed Thin Film Spreading Agents (TFSA). Substantial

increases in heavy oil recovery, as a result of applying these non-ionic additives, have been reported. For example, an extensive statistical study (54) reported the production cycle histories of 44 wells which received similar steam and TFSA chemical treatments. The results indicated an incremental oil production in the treated cycles of up to 85%. The effectiveness of these compounds has been attributed (55) to their ability to displace thick films forming at the interfaces between crude oil and the reservoir rock and water phases. In place of the thick flow-resisting films, very thin mobile films, which offer little resistance to coalescence and water-wetting of rock, are formed. This mechanism, essentially, amounts to destabilization of water-in-oil emulsions and favourable wettability changes. The selection of the most effective TFSA compounds, for actual complex reservoir conditions, may involve a compromise between the most effective spreading agent for the rock-oil interface and the most suitable compound for the rock-connate water-oil interface (48). The importance of selecting the optimum TFSA composition for a specific oil/water/rock system, is highlighted by the difference in the degree of success obtained with these compounds in the laboratory. For example, while one of the TFSA compounds resulted in up to 30% improvement in laboratory synthetic core flooding tests (56), another formulation (Thermoflood 808) was reported (46) to have no effect on laboratory bitumen recovery under flooding or drawdown conditions.

The performance or survival of organic steam additives in the very alkaline high temperature boiler effluent environment has not been adequately assessed. Significant improvements in oil recovery, due to the application of steam additives, have been reported in a number of pilots in the United States but more work needs to be done to assess potential benefits of these additives with Canadian heavy oils.

In the laboratory it is impossible to recreate the changing reservoir conditions produced by steam injection. Data on the high temperature chemistry of steam additives or even high temperature alkali/crude reactions is very inadequate. This field research program studied a steam additive, high temperature alkali/crude reactions, and emulsions under real conditions.

B. STUDY PROGRAM

1.0 SELECTION OF WELLS

1.1 Introduction

The area selected for the study is part of the Gulf Pelican Lake Heavy Oil Pilot Project located approximately 275 km north of Edmonton, Alberta. The Pelican Lake Project is situated in a large heavy oil deposit known as the Wabiskaw Oil Sands (Figures 1 and 2).

Initial development of the area started in 1978 with the drilling of a well in LSD 6-9-81-22 W4M. Further drilling was continued to confirm the results during 1978/79. Over the period of 1980/81, a total of 38 wells were drilled to complete seven 7 spot patterns with the objective of determining the most suitable method to produce the heavy oil deposit. Construction of production facilities and primary production from this area, referred to as the Pelican Pilot Project, commenced in 1981.

Further development outside of the original pilot area, referred to as the Pelican Area Development, continued in parallel with the Pelican Pilot Project. The objective of this operation was to confirm the continuity of the Wabiskaw formation and further evaluate other stimulation techniques. Experimentation outside and within the pilot area included various stimulation/recovery methods including cyclic steaming, steamflooding, waterflooding, fireflooding, oxygen enriched fireflooding, and horizontal well production techniques.

1.2 Geology

The Wabiskaw Oil Sands, the lowermost member of the Lower Cretaceous Clearwater Formation (Figure 3), are marine deposits originating with the initial transgression of the Clearwater Sea of late early Albian Age. The Wabiskaw formation is categorized in three deposits: the Wabiskaw A, B, and C, and are mappable blanket sands, each regionally lobate in character. All are located on the southwest slope of the southern end of a 100 kilometer wide sub-basin that was connected to the northern Boreal Ocean. The three Wabiskaw deposits all have a similar sedimentology and a coarsening upwards log character. They are glauconitic and have all the characteristics of marine offshore shelf sands. However, their regional geometry and position in the basin suggests that they originated as submarine fan deposits. Subsequently, they were reworked on the shallow shelf floor as offshore bars.

Grain Size

Each of the three Wabiskaw deposits is a sequence that invariably coarsens upwards producing a barrier bar like response on gamma ray well logs. Grain size analyses from the sands confirm this. These analyses show that the sands are predominantly fine grained sands, ranging from very fine grained near the base, to fine grained or medium grained at the top. Recent work suggests there is no consistent spatial variation in grain size in the study area.

Lithology

The coarsening upwards cycle in the Wabiskaw A sand is a result of a transition from laminated clay mud at the base through very fine grained silty, sandy clay mud, which is in turn overlain by a bioturbated to generally massive sand. This sand itself coarsens upwards (from very fine grained at the base to up to medium grained near the top - Figure 4) due to the lower portion of the sand being muddier and containing numerous lenses or pods of bioturbated clays, silts and sand.

Facies Analysis

We consider the Wabiskaw deposits to be part of a shallow marine shelf bar system in which:

Shelf - claystone units
Bar Complex Margin = lower bioturbated "dirty" sand
Bar Complex = upper clean sand
(See Figure 5)

Pay Distribution

Oil pay, confined to the Wabiskaw A sand in the Pelican Pilot Site area, has been defined primarily by using a 35 ohm resistivity cutoff to indicate 5 wt.% oil or greater. The trapping mechanism for the oil in the Wabiskaw is a combination structural and stratigraphic trap. Regional dip is to the southwest and the oil is trapped against the updip pinchout of the Wabiskaw Sands. The oil/water contact is inclined to the southwest suggesting that emplacement and degradation took place before the present day southwest structural dip was fully attained. The net pay is provided in Table 1.

Porosity

Around the Pelican Pilot Site the average effective porosity over the entire interval of net pay is around 25% to 26%. This increases towards the southwest due to the

cleaner sand buildup, and decreases to the northeast. A controlling factor is the facies type (i.e., relative thickness of bar complex and bar complex margin facies). The effective porosity of the bar complex sand facies is typically 28.5%.

Oil Saturation

Average oil saturation of the entire Wabiskaw A net pay interval is around the .68 to .72 range near the pilot site, this increasing to the southwest and decreasing to the northeast. Locally, oil saturation appears to be more sporadic and random in its occurrence.

Permeability

Average permeability values near the pilot site range around 400 to 900 md. This average increases to the southwest and decreases northeast. Absolute permeabilities are up to 2.0 darcies.

Weight Percent

Average weight percent bitumen values around the pilot site range from about 7.5 to 8.5 wt. %.

Viscosity

Average viscosity at the pilot site is about 1.2 x 10^{3} mPa.s, but the viscosity increases rapidly to the southwest. This is coincident with a rapid drop in structural elevation of the Wabiskaw A sand toward the southwest. Northeast of the pilot site the viscosity increases again and probably continues to climb.

The Pelican area is an anomaly amongst oil sands deposits with respect to viscosity. The Pelican Wabiskaw A oil viscosity is abnormally low (1.2 x 10^{6} mPa.s versus 10^{9} mPa.s in the Athabasca deposit) for an oilsands deposit, and is more akin to oil found in the Lloydminster heavy oil belt.

The main reservoir parameters of the Wabiskaw "A" Sand are shown in Table 1.

1.3 Selection Criteria

A group of 18 primary production wells drilled in 1986 were examined to select candidates for the steam additive study. Ten of the wells are located north of the pilot area on

twenty acre/well spacings in an area which has been designated for purposes of this study as "Area I". The remaining eight wells are located south of the pilot area on 15-20 acre/well spacings in an area designated as "Area II".

Two pairs of wells from each area were chosen, based on geological factors, drilling and completion techniques, historical production profiles (oil and water), and overall operational logistics. This comprehensive evaluation involved comparisons of net pay, bulk oil saturation, viscosity, initial reservoir pressure, log analysis, and core/bit sample examination.

The Area I and Area II wells are producing from similar net pay, with the thickness being about 0.5 m greater in Area II than Area I. Log correlations between the well pairs, however, show sand thickness in the bar complex and bar margin varying by less than 0.25 m in all well pairings. It was not believed that these slight variations in net pay thickness would significantly affect oil production responses.

The porosity and permeability of the reservoir appears consistent throughout both areas. The variation in neutron/density indicated porosity is a mere 1 to 2% porosity in a poorly consolidated (i.e., very porous) sandstone. Grain size distribution and clay-mineral content is also similar between the areas. Argillaceous content, as indicated by gamma ray log, differs by only 5 API units between wells.

The bulk oil saturations in paired wells are very close and in addition, there is no major discrepancy in oil saturations between Area I and Area II.

Between the two areas, oil gravity and composition are similar, with oil viscosity varying by only 100-200 centipoise. This variation in viscosity was not expected to result in any significant difference in oil production response after steaming in a heavy oil pool.

The initial reservoir pressure in the two areas was at virgin reservoir pressure (see Table 1). No pressure depletion had occurred prior to commencing primary production due to the fact that the study wells are located at least two full sections away from existing pilot operations.

Area II wells produced, in primary, with a 10% to 15% higher water cut than the Area I wells. This difference is believed to be due to a strong NE-SW structural trend in the Wabiskaw A sand structure. Localized structural noses and closures in both Areas I and II illustrate this trend.

Differences in water production between the areas may be related to this structural trend, as higher oil and relatively lower water production rates appear to occur along structurally higher areas. Regionally, however, Area I does not appear to differ substantially from Area II in terms of Wabiskaw Structure.

Primarily due to the difference in water production from the two areas, two well pairs were chosen from each area. As evidenced in the well logs, water saturation in the well pairs was very constant. Pairing in this manner also minimizes any effects of minor structural differences.

From a geological perspective, only very minor differences in the well pairings were detected from log analysis and core/bit sample examinations. Log cross sections were constructed and examined to illustrate the similarity of the four well pairs.

From a reservoir standpoint, all wells within the same area were appropriately matched as well pairs for the purpose of this study. By choosing the well pairs within each of the two areas, an opportunity to quantify the effect of steam additives in areas with differing watercuts was identified.

From an operational viewpoint, an attempt was made to match pairs of wells which were geographically close together and exhibited approximately the same cumulative primary oil/fluid production. It was concluded that similar reservoir depletion would provide similar steam penetration into the reservoir. The completion techniques and the well orientation (vertical versus deviated) were taken into consideration in matching study wells. No significant differences in sand production was observed between study wells during the primary production period.

It was believed that by comparing the performance of four cyclically steamed wells without additive to four matched wells with additive, a reasonable test base would be supplied. Evaluation of the wells in Area I and Area II yielded the following well pair selections:

<u>Area I (North)</u>

(1)	15-17-81-22 W4M	(non additive)
	10-17-81-22 W4M	(additive)
(2)	9-17-81-22 W4M	(non-additive)
	7-17-81-22 W4M	(additive)

Area II (South)

(3)	8-4-81-22 W4M	(non additive)
	12-3-81-22 W4M	(additive)
(4)	8A-4-81-22 W4M	(non-additive)
	5A-3-81-22 W4M	(additive)

Figures 6 and 7 indicate location of the study wells within the project area.

2.0 SELECTION OF ADDITIVE

The following are the criteria used in the selection of the Pelican Lake steam additive:

i) Proven track record of oil production during field tests and adequate laboratory data base (7, 58-60).

ii) Thermal stability under boiler effluent conditions of 250°C and high alkalinity (59,60).

iii) Significant lowering of the interfacial tension of Pelican Lake crude and formation water (7).

iv) Compatibility with the carbonate and hydroxide ions in the boiler effluent (i.e. no additive loss by precipitation).

v) Compatibility with the reservoir water (i.e. no additive loss by precipitation).

vi) Low adsorption onto the reservoir rock.

vii) Low losses into the hydrocarbon phase while still having the ability to lower interfacial tension.

viii) Long term stability under reservoir conditions (59).

ix) No adverse effect on the viscosity of emulsions formed during the production phase.

x) Foam generation in order to improve sweep efficiency.

Suntech IV FA and Shell's ENORDET LTS 18 were selected for laboratory screening before the Pelican Lake field trial. Sun Tech IV FA is similar to Sun Tech IV except for the addition of an alkaline silicate. In some areas in California the Sun Tech IV FA has outperformed Sun Tech IV (58). The benefits of alkaline additive components under high temperature conditions are controversial. Sun Tech IV FA is sold as a 35% active solution.

Sun Tech IV™, an alkylaryl sulfonate, has been studied extensively in the laboratory and in the field in the U.S.A. It is an alkyl toluene sulfonate wherein the alkyl group is a mixture of C_{14} to C_{18} side chains having an average 16 carbon atoms (59). Sun Tech IV is a mixture of 60% m-alkyltoluene sulfonate (I) and 40% p-alkyl toluene sulfonate (II).

Sun Tech IV and various thin film spreading agents have been studied as steam additives for recovery of Canadian bitumen. In the laboratory, Sun Tech IV tripled bitumen recovery whereas the thin film spreading agents, Thermoflood 808 and 906, had very little effect on recovery (7,56).

The stability of steam additives under boiler effluent conditions of high temperatures and high alkalinity is of prime importance. Sun Tech Inc. were unable to measure any decomposition of Sun Tech IV at pH 11 and a temperature of 299°C for over 200 hours whereas their study of a typical commercial alpha olefin sulfonate at pH 11 and a temperature of 299°C showed a steady degradation with time (59). A TRW study by Raplie et al also showed excellent thermal stability of the alkyl aryl sulfonates (60).

Shell's ENORDET LTS 18 is quite similar structurally to Sun Tech IV and is produced by the alkylation of toluene with various linear olefins (62). LTS 18 is sold as approximately 13.7% active solution (62).

The linear alkyl toluene sulfonates are very thermally stable but have a greater sensitivity to multivalent ions than the alpha olefin sulfonates (62). This was not expected to be a problem at Pelican Lake where calcium and magnesium concentrations in the formation water are very low.

3.0 LABORATORY STUDY OF THE EFFECT OF STEAM ADDITIVES ON EMULSION FORMATION AND INTERFACIAL TENSION

3.1 Introduction

A number of factors were involved in finalizing the selection of the additive. The compatibility of the surfactant with the boiler effluents and reservoir water, the effect of the surfactant on emulsion formation, and the effect of the surfactant on interfacial tension were all studied in the laboratory. These tests were performed on both the Sun Tech IV FA and the Shell ENORDET LTS 18 additives.

Some surfactants will precipitate in the presence of the hydroxide ion from the boiler condensate or form insoluble calcium or magnesium salts when mixed with reservoir water. As the formation of precipitates with the reservoir water or injected fluid can remove the additive and significantly impair injectivity or well productivity, it was necessary to ensure the selected additive was compatible with both the reservoir as well as the injected water.

The effect of surfactants on emulsion formation is also of prime importance. Emulsification of the condensate with the heavy reservoir crude during steam injection may improve the sweep efficiency, but the formation of viscous emulsions during the production cycle can severely cut well productivity.

The literature indicates that lowering of the oil-water interfacial tension (IFT) is probably the dominant mechanism of improving oil recovery by steam additives. It was, therefore, important to analyze the IFT characteristics of the heavy crude-boiler effluent and heavy crude-reservoir water systems involved in this study. Only a few methods are suitable for measuring the low interfacial tension of such systems, with the spinning drop technique known to be the simplest and most effective of those methods. The IFT work was contracted to the Alberta Research Council in Edmonton.

3.2 Sample Origin

Reservoir water samples for the emulsion and IFT studies were from Pelican Lake wells, which were on primary production. The samples contained no added chemicals of any type.

The heavy crude samples for the emulsion and IFT studies were collected and stored in the dark to prevent changes in characteristics due to the ultraviolet light. For the

emulsion study, crude was decanted from the top of the produced fluid sample. It contained considerable water of droplet size 1-5 microns as shown in the photomicrograph Figures 8 and 9. Boiler condensate (from 80% quality steam) was used for the emulsion and IFT studies.

3.3 Compatibility of Steam Additives

Sun Tech IV FA additive was mixed at a concentration of 600 mg/L with boiler effluent and with reservoir water. These solutions were tested at 80°C for one hour and at 5°C for one hour. No precipitates were formed. The experiment was repeated with Shell ENORDET LTS 18 and again, no precipitates were formed. It was therefore concluded that both additives were compatible with the boiler condensate and reservoir water (Table 2).

3.4 Emulsion Tests

Reservoir water was blended in various proportions with the reservoir crude. The various crude oil-water mixtures were blended at 16 000 RPM on a Hamilton Beach Mixer as outlined in API RP42 emulsion testing procedure. The emulsions were poured into 100 mL graduate cylinders in an 80°C bath and the break times measured. A water content of 20% was the maximum amount that could be emulsified with the crude. The break times were five minutes as shown in Table 3. The emulsions were photographed immediately after blending (Figures 10 and 11).

The experiment was repeated with Sun Tech IV FA and with Shell ENORDET LTS 18 at a concentration of 600 mg/L in the reservoir water. Again, the maximum water that could be emulsified was 20% and the emulsions broke in five minutes. The data is shown in Tables 3 and 4. No unusual emulsification problems during production were expected, based on this data.

The test was repeated, using boiler condensate (from 80% quality steam) with and without Sun Tech IV FA and Shell ENORDET LTS 18 at 600 mg/L. In the three cases, relatively stable emulsions were formed in all proportions. The emulsions formed in this case had potential to act as divertants and improve sweep efficiency in the reservoir. Photomicrographs for all cases are shown in Figures 12-21.

3.5 Interfacial Tension

The spinning drop method involves measuring the shape of a liquid drop or gas bubble in a more dense liquid contained in a rotating horizontal tube. The theory of this method is based on the balance between the centrifugal forces and interfacial forces acting on the drop. When a fluid drop (gas bubble or liquid drop) is injected into a liquid of

higher density contained in a rotating horizontal tube it becomes subject to elongation along its axis of rotation. The drop reaches an equilibrium elongation as the deformation forces due to the applied centrifugal field are balanced by the interfacial tension. If the density difference between the two fluid phases (Δ P), the diameter of the drop (D), its length (L) and the rotation speed (w) are measured, the interfacial tension is then calculated according to the following equation:

$$IFT = \frac{1}{32} \Delta P \, w^2 D^3 f \, (L/D)$$

In this equation f (L/D) is a shape factor which accounts for L/D effects associated with short drops (L/D <4). For high rotation speeds and/or low interfacial tension, the length-to-diameter ratio may be greater than 4. Under such conditions, the interfacial tension equation is reduced to:

$$IFT = \frac{1}{32} \Delta P \, w^2 D^3$$

For short drops, Slattery and Chen have given detailed tabulation of the value of the shape parameter as a function of maximum length-to-diameter ratio.

A heavy crude sample from primary production at Pelican Lake well 5A-3 was de-watered by spinning the sample at approximately 400 000 g for half an hour in an ultracentrifuge. Densities at 25.0, 50.0 and 75.0°C were determined using a densimeter. Generally, stabilized readings are taken at 5 to 10 minutes, but at 75°C the sample was slowly evaporating, so the density was calculated from the first data point.

The interfacial tension of Pelican Lake crude is shown in Figure 22 and Table 5 for mixture with the following fluids:

1) boiler condensate

2) reservoir water

3) reservoir water containing Shell ENORDET LTS 18 at 5 g/L.

The Pelican Lake crude with the reservoir water has the highest IFT. The alkaline components of the boiler condensate, hydroxide, and carbonate significantly lower the IFT's, particularly at temperatures that would occur in the reservoir (<125°C). Shell LTS 18 significantly reduced the IFT of the reservoir water at all temperatures.

The changes in the interfacial tension of Pelican crude in formation water containing Shell LTS 18 at 5 g/L are shown in Table 6 and Figure 23. The equilibriated values at various temperatures are plotted in Figure 24.

A comparison of Sun Tech IV FA with Shell ENORDET LTS 18 at concentrations of 5 g/L is shown in Figure 25 and summarized in Table 7. Sun Tech IV FA performed well at low temperatures and at low concentrations and, as can be seen from Table 8 and Figure 26, the performance at 0.05 g/L was much better than at 5.00 g/L. This is a very desirable feature.

Sun Tech IV FA and Shell ENORDET LTS 18 both performed very well in the laboratory studies. Sun Tech IV FA was selected over the Shell product for the Pelican Lake study for the following reasons:

i) Lower price of Sun Tech IV FA.

ii) Higher active concentration of surfactant in Sun Tech IV FA. (Sun Tech IV FA - 35% active, Shell ENORDET LTS 18 - 13.7% active). The higher active concentration significantly reduces shipping costs.

iii) The Sun Tech IV and Sun Tech IV FA have been extensively field tested

iv) The Sun Tech IV FA contains an alkaline silicate. Although the benefits of the silicate under steam injection conditions are controversial, the silicon concentrations in produced fluids from additive and non additive wells should provide useful data on in-situ reactions. Due to the high permeability of the Pelican Lake reservoir and the injection of a very alkaline boiler effluent, any adverse effects from the silicate were expected to be negligible.

4.0 SAMPLING PROCEDURES

Sampling procedures and schedules were set up and tailored to expected process phases during steaming and production periods. Attachment 1 indicates the sampling procedure and schedule for a typical study well. For each well, produced fluid (oil and water) samples were being taken initially during the primary (pre-steam) production phase. During the steaming period, samples of both steam generator, source water, and boiler effluent (condensate) were taken, as well as any pre-flush/workover fluids. More frequent produced fluid sampling took place for the initial high water cut flowback period, when some of the steam additive was expected to be produced back.

Wellhead samples of the produced fluids were taken on a gradually reduced frequency as the number of days that the well was "on production" increased.

The samples taken for interfacial tension measurements and emulsion studies were collected in bottles protected from the light by foil. Rigid films formed at the bitumen/water interfaces are photolytically induced and are not formed in the absence of light (64). These membraneous films can significantly alter the interfacial tension of the bitumen/water phase and affect emulsion forming tendencies.

5.0 CHARACTERIZATION OF RESERVOIR FLUIDS FROM PRIMARY PRODUCTION

Interfacial tension measurements were made on produced water/crude samples using the spinning drop tensiometer. These measurements provided baseline data before injection of surface active steam additives and alkaline boiler effluents.

Properties of the crude such as acid number, viscosity and specific gravity were measured (see Tables 9 and 10 and Figure 27). The chemical composition of the reservoir water was determined by plasma emission spectrometry and by standard methods of water analysis such as potentiometric titrations and ion chromatography. The following were analyzed: pH, hydroxide, carbonate, bicarbonate, chloride, sulfate, potassium, calcium, magnesium, silicon, aluminum and other trace elements. Measurements were taken at temperatures from 50-150°C.

Two water samples from primary production were analyzed for the Area II wells (Table 11). One of these samples, however, was not used for purposes of fluid characterization as it was believed to be contaminated with KCl workover fluid. Due to the low watercuts encountered during primary production, it was impossible to separate enough water for analysis from the Area 1 wells. It was therefore assumed for analytical purposes that reservoir water composition was consistent between the two areas.

6.0 CYCLIC STEAMING OF WELLS

Steam injection conditions were matched as closely as possible on the four pairs of wells selected. By utilizing the same source feed water within each of the two areas, an attempt was made to maintain a consistent boiler effluent for each group of study wells.

The optimum operation of the 25 MMBTU/hr Struthers steam generator supplied an average steam quality of 80%, with slight daily variations from 76% to 84%. Due to its effect on downhole steam quality, an attempt was made to maintain equivalent distances of insulated portable surface steam line from the generator to the injection wellhead for each of the well pairs.

Although mechanical breakdowns and operational difficulties are often unavoidable when using portable trailer - mounted steam generators, no major steam injection problems were encountered. The steam injection phase of the study was completed very smoothly and the steaming parameters (steam rate, steam quality, steam slug size) were kept consistent within each of the two areas.

Basically, the steaming cycle started with a low steam rate in order to preheat the wellbore and avoid any significant thermal shock. Following this preheat phase, the steam rate was increased close to the maximum until stabilized injection conditions were achieved, and was maintained at this rate over the entire cycle of steaming, until the required steam slug was injected.

The sequence in which the study wells were steamed is as follows:

15-17	Non-additive)	
9-17	Non-additive)	Area I
10-17	Additive)	
7-17	Additive)	
8-4	Non-additive)	
8A-4	Non-additive)	Area II
5A-3	Additive)	
12-3	Additive)	

Figures 6 and 7 indicate that within each of the two areas there are eight wells that have been steamed (four study wells and four non-s÷udy wells).

The steam slugs that were injected in the study wells from Area I were very similar in size (within 5 - 10%) and were also consistent with the average steam slugs used in the non-study wells from the area. To indicate the degree of

consistency of the steaming parameters for the study wells, please refer to Figures 28-31. One of the most representative parameters which describes injection behavior is the Injectivity Index, which is the ratio between the daily fluid volume injected and the average wellhead pressure at which that fluid is injected. In order to obtain a "base-line" performance for the injection period, an average Effective Injectivity Index was calculated for all eight wells (study and non study) which were steamed in Area I. The term "effective" refers to the effective thickness in which the steam enters the net pay. Following this step, the study wells were individually compared, from an Effective Injectivity Index point of view (dashed line), with the average Effective Injectivity Index for the area. The same procedure was followed for Area II.

From Figures 28-31 it can be observed that the Area I study wells are consistent from a steam injection phase perspective. The average steaming parameters for the area are very consistent with each well. Maintaining consistency during the steaming phase is of great importance in order not to induce any factor which may alter the evaluation of the oil production response after steaming.

Figures 32-35 indicate the steaming performance of the wells from Area II. The Effective Injectivity Index of the individual wells is similar with the average value for the area, which indicates consistency was also achieved on Area II. However, the Effective Injectivity Index is higher for Area II than that for Area I, although the same daily steam volumes were injected in both areas. It has been concluded that the main reason for this difference between the Effective Injectivity Indexes of the two areas is that Area II, with a higher water content, is more oil depleted and/or its local compactness is lower. Therefore, more steam had to be injected in Area II wells before stabilized conditions were achieved. Nevertheless, almost the same amount of steam was injected in <u>all</u> study wells after the stabilized conditions occurred. The additive was injected into the additive wells after stabilized injection conditions were achieved. The additive concentration was kept constant with respect to the amount of steam injected each day during the additive injection period.

Figures 36-39 show the consistency achieved during the additive injection in the four additive study wells. Recognizing that the daily steam volume injected was almost the same in all wells, the additive injection went very

well. The graphs illustrate the additive concentration (100% active substance) expressed as ppm of the daily steam volume injected. It can be observed that an injection concentration of approximately 500 ppm was maintained in all four additive wells.

The wellhead pressure was closely monitored prior to, during, and after additive injection. It was believed that some potential foaming tendency of the surfactant could have caused an increase of the injection pressure for the same steam rate. No significant changes in the wellhead pressure were observed in any of the additive wells during the additive injection. This indicates that even it some foaming was taking place, it was not of great significance.

After the steam injection was completed, a routine three days of soaking (well shut-in) followed in all the study wells, as was the case with non-study steamed wells from Area I and II. Once the soaking period was over, the wells were placed on production.

7.0 SAMPLE COLLECTION

The sample collection followed the schedule provided in Attachment 1 throughout the study period, and was completed by the beginning of July, 1988. On a routine basis, the collected samples were sent to a commercial laboratory to allow testing of physical and chemical properties.

Attachment 2 indicates all the actual samples taken, over the study period, from all the eight wells. Generally, samples of produced fluids were taken over a four month period after steam injection was complete and the wells were placed back on production. It was concluded that sampling after this period was unnecessary, as the production response from cyclic steaming was complete.

The types of samples which have been taken are as follows:

- One litre sample of source water with 1% KCl injected prior to injecting the steam to "condition" the reservoir.

- One litre source water sample and two one litre boiler effluent samples taken on each steam slug. The boiler effluent samples were spread out over the fifteen to eighteen day injection period to provide a representative injected fluid composition. The boiler effluent samples were taken from the steam quality pot/trap to correctly obtain the high pH liquid phase of the steam.

- One litre samples of produced fluids (oil and water) during the flowback and pumped production period. This was done frequently immediately following steaming with the frequency diminishing with time. Due to the possibility that the initial flowback was an important time for steam additive observation, the wellhead samples were taken on a six to twelve hour basis for the first day and on a frequency of a sample per day following this. One month after running the pump, the produced fluid sampling frequency was decreased from daily to weekly for one month and once every two weeks thereafter.

8.0 CHARACTERIZATION OF PRODUCED FLUIDS AFTER STEAMING

Boiler feeds, boiler effluents, and produced water samples were analyzed using plasma emission spectrometry. Anions were determined by standard methods (e.g. potentiometric titration of hydroxide and carbonate) and by instrumental methods such as ion chromatography for sulfate and chloride. An ion chromatography method was developed for determination of the alkyl toluene sulfonate steam additive in the produced waters.

The results fo the source water (boiler feed) analysis are shown in Table 12 while Table 13 shows the analysis fo the boiler effluents during steaming of the eight study wells. Produced water analysis for each of the eight wells are shown in Tables 14-21.

The surfactant and selected ion concentrations (Na, Cl, HCO_3, Si, Al) found in the produced water samples have been plotted in Figures 40-83 for each of the study wells.

Alkalinity

The boiler condensates, as shown in Table 13, have high pH values (11+) and high alkalinities. The reaction of this fluid with the reservoir minerals is very rapid under the high injection temperatures. The pH drops rapidly in the reservoir due to the reactions with the reservoir minerals (1). As shown in Tables 14-21, even the first flowback samples from all wells show little or no hydroxide ion present.

Silicon/Aluminum

The high alkalinity of the boiler condensate and the elevated temperatures cause fluid/rock interactions to occur at accelerated rates. Significant amounts of silica can be dissolved and then reprecipitated at a later stage in the process. The alkaline boiler effluent can swell clays, disperse fines, and precipitate new minerals such as analcime. The high alkalinity of the boiler condensate is rapidly reduced by reactions with the minerals and the pH can drop several units in a very short distance in the reservoir.

The silicon concentrations plotted in Figures 40-47 are primarily generated by the alkaline boiler condensate reactions with the reservoir minerals but a small amount was injected in the additive wells as the alkaline silicate component of Sun Tech IV FA. The silicon concentration in

Sun Tech IV FA is 20 600 µg Si/g. Since the additive was injected at a rate of 500 ppm, the injected silicon concentration was 35 ppm. As can be seen from Table 13, a small amount of silicon is also present in the boiler condensate.

As can be seen from the plots, the addition of the surfactant appears to have had little effect on the production of silicon and thus the rate or extent of fluid/rock interactions. Silicon production trends appear similar in both the additive and non additive wells.

The presence of aluminum in the produced water is also an indication of the extent of fluid/rock interactions. As such, it is expected that the aluminum ion concentrations would follow a similar trend as the silicon. It is, however, more difficult to interpret the aluminum ion information due to problems with preserving the aluminum in the samples. Bearing this in mind, Figures 48-55 support the silicon data as they do not indicate that fluid/rock interactions have been altered through the addition of a surfactant.

Chloride

In order to determine the formation water fraction of the produced fluid, a water soluble tag chemical is required, which is present either in formation water or in injected water, but not in both. The chemical must also be stable with temperature and time (66).

Chloride is the predominant anion in most oil sand reservoirs, while the Cl concentration of injected steam condensate is usually low. Normally, formation water can be considered to be the only significant source of dissolved Cl. The concentration of Cl in the formation water therefore represents the limiting value for Cl. A measurement of Cl content can therefore be used to calculate the proportions of reservoir water and injected water in a produced water sample (66).

This method was used to determine the amount of injected water recovered from all study wells. The chloride ion concentration found in the produced water from the study wells is shown in Figures 56-63. In general, it can be seen from these plots that the chloride ion concentration is usually higher and remains more consistent than the non additive wells, which show an increasing trend over time. This indicates that more reservoir water was being produced in the additive wells. Calculations confirmed this trend with the results being discussed later in Section 10.4.

Sodium/Bicarbonate

Sodium ion concentrations are plotted in Figures 64-71. This ion, along with bicarbonate ion concentration (Figures 72-79), are also used to assist in determining trends between injected and reservoir water recovery. As these ions both participate in fluid/rock interactions, they are much less reliable than the chloride ion for quantitatively determining reservoir/injected water proportions. Both the sodium and bicarbonate plots appear to support the chloride ion data, in that both tend to indicate higher reservoir water concentrations in the produced fluids from the additive wells.

Potassium

In order to perform workovers on the wells, they were killed with a KCl fluid. Production of this fluid after the workover completion was able to contaminate the wellhead samples taken, thus not providing an accurate representation of the actual fluid produced from the reservoir. Unusually high concentrations of potassium in the produced fluid was an indication of contamination of the sample. These samples, as noted in Tables 11-21, were not used in quantitative interpretation of results (i.e. reservoir/injected water proportions).

Surfactant

Plots of the surfactant concentrations found in the produced water of the additive wells are shown in Figures 80-83. Samples from non additive wells were also analyzed for surfactant to confirm that soaps were not being formed in situ. The plots show that all additive wells demonstrated a similar trend with respect to surfactant production. These trends, as well as the amount of surfactant recovered, are discussed in more detail in Section 10.4.

9.0 DATA MANAGEMENT

9.1 Injection Data

All the pertinent steaming data was collected and compiled daily. The steaming parameters which have been gathered are as follows:

- hours on injection
- steam rate, (m^3/day)
- steam volume, (m^3/day - using continuous recording charts)
- steam quality, (%)
- steam temperature at the boiler's outlet, (°C)
- steam pressure at the boiler's outlet, (kPa)
- steam temperature at the wellhead, (°C)
- steam pressure at the wellhead, (kPa using a pressure gauge and a continuous recording Barton chart recorder).

After this data was compiled, computer routines were developed in order to analyze and compare the behavior of the study wells during the steaming phase.

Section 6 discusses the parameters used to compare the steaming performance of the study wells (i.e., "Effective Injectivity Index"). Several computer routines were developed in order to manipulate the steaming data. Some routines were used to generate the average value of the Effective Injectivity Index for each of the two areas (Area I and Area II, respectively). Other routines calculated the Effective Injectivity Index for individual study wells. A final routine compared the individual Effective Injectivity Index with the average value for the area. As discussed in Section 6, the results are shown in Figures 28-35.

9.2 Production Data

During the production cycle, the study wells produced into independent tanks at each location. Fluid levels were measured to determine total fluid production on a daily basis. Wellhead samples were collected and analyzed in the on site laboratory to determine the relative percentage of oil, water and solids. The production parameters that were collected and compiled daily are as follows:

- hours on production
- oil volume, (m^3/day)
- water volume, (m^3/day)
- sand cut, (%)
- wellhead temperature, (°C)
- casing pressure, (kPa)

In addition to this production data, a series of data files and computer routines were developed and implemented to facilitate analysis of produced water chemistry and surfactant concentration in the produced fluids. The variation of the concentration of various key ions over time in produced fluids (Bicarbonate, Chloride, Sodium, Silicon and Aluminum) were inputted into a computer and then plotted. These graphs, (Figures 40-83) have been discussed in Sections 5 and 8.

10.0 PRODUCTION RESPONSE ASSESSMENT

This report section describes the actual oil and water production response of the study wells. Well performance is first analyzed on an area basis, with each well being compared to its respective partner as well as the average performance of all steamed non-additive wells in the area (includes both study and non-study wells). The average performance of both study and non-study wells has been included as an analytical tool due to the difficulty which was encountered in interpreting data when comparing the study wells to their respective partners only. As the geology within each area is very similar and steaming procedures were identical for both study and non-study wells, it was concluded that including non study wells in the calculation of production averages for each area was reasonable.

In addition, the production response from steaming has been compared for the two areas. Average and cumulative water and oil production have formed the basis of this comparison.

10.1 Production Performance on Area I

Area I was designated as the area located north of the pilot facilities consisting of ten wells, eight of which were steamed (four study and four non-study). The performance of the study wells, as well as the average performance of the area, is illustrated in Figures 84-91. Oil rate, water rate, cumulative oil, and cumulative water production are represented in these plots. In order to retain the confidentiality of actual production data for this experimental project, daily production data has been expressed as a percentage of the average peak rate of the non-additive wells in the area. Similarly, cumulative oil and water has been expressed as a percentage of the average cumulative oil and water for the area.

Well Pair 7-17-81-22 W4M (additive) / 9-17-81-22 W4M (Non-additive)

As with all other wells, production data for 7-17/9-17 has been compiled for a period of 210 days (seven months) after the well was placed on production following steaming. It has been concluded that this is an adequate length of time to assess the impact of steaming, as the wells will have returned to production levels equivalent to rates experienced prior to steaming.

Well 7-17 had excellent on line time over the period examined, being shut-in for only one day to accommodate a routine bottomhole pump changeout. Well 9-17 also had excellent on line time, having no operational problems which required the well to be shut-in.

As can be seen from Figure 84, the additive well (7-17) produced less oil over the period examined than both the non-additive well (9-17) and the average production for the area. Well 7-17 produced only 84% of the average non-additive oil production for the area while 9-17 exceeded the average by approximately 7%.

Both wells exceeded the average water production for the area. Well 9-17, the non-additive well, exceeded the average by 25%, while 7-17 was 42% above the area average. This excessive water production is viewed as a negative effect, as additional costs are incurred for handling, treating, and disposal. This is illustrated in Figure 85.

Figures 86 and 87 illustrate the oil and water production rates expressed as a percentage of the average peak rate. The peak oil rate for the non-additive well, 9-17, exceeded the average peak rate for the area by 30%. Well 7-17, however, only attained a peak rate which was 4% above the area average. Peak water production rates exceeded the area average for both wells , 9-17 by 50% and 7-17 by 35%.

Well Pair 10-17-81-22 W4M (Additive)/15-17-81-22 W4M (Non Additive)

Over the seven month period the non additive well (15-17) experienced 13 days of downtime due to sand cleanouts and bottomhole pump changes. Its additive pair well, however, had no downtime over the same period of time.

In this well pairing 10-17, the additive well, out-performed both the area average as well as its non-additive partner with respect to oil production. Figure 88 shows that 10-17 produced 6% more oil than the area average while 15-17 only managed to produce 82% of the non additive average for the area.

From Figure 88 it can be seen that cumulative water production from 10-17, the additive well, exceeds the area average by 16%. Cumulative water production from 15-17, however, essentially matched that of the area average.

It is interesting to note that the peak oil production rate for 10-17 (Figure 90) reaches 150% of area average. This

peak oil production rate was the highest ever observed for a cyclic steaming operation at the Pelican Lake Project. The peak oil production rate for 15-17 was 14% higher than the area average.

Peak water production rates, as illustrated in Figure 91, were higher than the area average for both wells. The average was exceeded by 2% and 20% by 10-17 and 15-17, respectively.

10.2 Production Performance on Area II

Area II was designated as the area located south of the pilot facilities consisting of eight wells (four study and four non study) being steamed. The performance of these wells, as well as the area average, is shown in Figures 92-99. The plots have been assembled in the same manner as that for Area I, in order to maintain confidentiality of explicit production data.

Well Pair 5A-3-81-22 W4M (Additive) / 8A-4-81-22 W4M (Non Additive)

Well 5A-3, the additive well, experienced the most downtime of any well involved in the study. Cold weather, frequent sand cleanouts, and pump changes forced the well to have 49 days of downtime over the 210 day period. The non additive well, 8A-4, had only 9 days of downtime over the same length of time.

Surprisingly, even with 49 days of downtime, 5A-3 managed to exceed average cumulative oil production for the area by 12%. This is illustrated in Figure 92. In addition, it should be noted that 5A-3 produced 100% water for the first two months after being placed on production, a period far longer than any other study well. 8A-4, the non-additive well, closely matched cumulative oil production for the area throughout the seven month period.

Figure 93 shows that 5A-3 also exceeded the average cumulative water production for the area by 31%. 8A-4, however, produced only 102% of the average for the area.

Oil production rate profiles, expressed as a percentage of the average peak value for the area, are shown in Figure 94. As seen in the graph, both wells experienced higher peak oil production rates than the area average. 8A-4 achieved a maximum rate which was 148% of the average peak rate, while 5A-3 achieved a rate of 38% above the area average. It is interesting to note that these profiles look much different than those generated for Area I. This is primarily due to the fact that wells on Area II did not

experience as large a "peak" oil and water production rate after steaming. Consequently, as individual well performance is compared to the average peak production for the area, the profiles from Area I and Area II appear much different.

Figure 95 illustrates the water rate production profiles for the wells. Both wells had peak water production rates above that of the area, with 8A-4 exceeding the average by 10% and 5A-3 by 50%.

Well Pair 12-3-81-22 W4M (Additive)/8-4-81-22 W4M (Non-Additive)

Both wells experienced approximately the same amount of downtime over the seven month period. Well 12-3, the additive well, was down for 9 days, while 8-4 was down for 13. Downtime in both cases was mainly due to necessary sand cleanouts or pump changes.

Figure 96 shows cumulative oil production for the wells. Unlike the other well pair in this area, the non additive well (8-4) out-performed the additive well with regard to total oil production. 8-4 produced 25% more oil than the area average, while 12-3 produced approximately the average volume for the area.

Cumulative water production for the period examined is illustrated in Figure 97. Both wells exceeded the average water production for Area II. The additive well produced 160% of the area average, while 8-4 produced 132% of the average.

The oil production rate profiles, shown in Figure 98, indicate that both wells had peak oil production rates greater than the average for the area. Well 12-3 exceeded the average peak rate by 68%, while 8-4 exceeded the same value by 78%.

Figure 99 shows that both wells achieved peak water production rates greater than the average peak value for the area. The average peak production was exceeded by 64% and 38%, by 12-3 and 8-4, respectively.

10.3 Performance Comparison Between Area I and Area II

In order to analyze the general performance of the steamed wells in Area I in comparison to the wells from Area II, average oil rate, average water rate, average cumulative oil production and average cumulative water production were examined for each area. The performance of Area II is graphically compared to the performance of Area I in Figures 100-103. As with previous production data, the

graphs have been assembled so that explicit data is not released. Instead, the pertinent production data from Area II has been expressed as a percentage of the equivalent data from Area I.

Figure 100 shows a comparison between the average oil production rates for the two areas. As shown on the graph, the wells on Area II did not experience as strong an oil production response after being placed back on production as did the wells from Area I. The Area II wells, however, did not experience as sharp a decline in oil production rate after the initial production response as did the Area I wells. This is evidenced in the period of approximately 50 to 175 days after commencing production in which the Area II wells surpassed the Area I wells with regard to oil production. In the final month of production examined, the wells produced at approximately the same rate.

Figure 101 compares the cumulative oil produced from Area I with the cumulative oil produced from Area II. Due to the fact that oil production rates were much lower in Area II during the initial production response, the average cumulative oil produced by Area II wells is only 78% of the average produced by Area I wells.

Over the majority of the period, water production rates from the Area II wells appeared to average approximately five times that of the average for Area I wells. That is believed to be because more steam had to be injected into the Area II wells prior to achieving the stabilized injection conditions. Consequently, more water has been produced back. This is evident in Figure 102. As previously mentioned in Section 1, the wells in Area II produced with a water cut 10 - 15% higher than the Area I wells during primary production.

Cumulative water production for the two areas is shown in Figure 103. From the graph it can be observed that over the seven month period Area II produced approximately 3.5 times the water from Area I.

10.4 Discussion of Results

The study has not provided, from an oil production performance perspective, any definitive evidence to indicate that the cyclic steam stimulation process is enhanced through the addition of Sun Tech IV FA chemical. No consistency could be observed in oil production trends between the additive and non additive wells.

In Area I, one additive well outperformed both the area average and its non additive partner in terms of oil production, while the other additive well did not. Steam and additive injection techniques, however, were consistent between all the study wells. No trends, therefore, can be seen from examination of oil production in Area I. One interesting point, as mentioned previously, is that one of the additive wells in Area I achieved a peak oil production rate greater than that of any cyclically steamed well in the Pelican Project history.

Examination of oil production volumes from Area II yielded a slightly more positive assessment. One of the additive wells exceeded average oil production for the area, while the other additive well produced a volume approximately equivalent to the area average. As Area II had a higher initial watercut than Area I, this leads to speculation that the additive may be more effective in a higher water content environment. To base any conclusions on this observation, however, would be premature as the test base used is very small.

Unlike the oil production response, the effect of cyclic steam stimulation with Sun Tech IV FA on water production appears quite pronounced. In every case, water production from the additive wells exceeded both the area average, as well as its non additive partner. Water production from the additive wells exceeded their respective area averages by amounts varying from 16-60%. This increase in water production is viewed as a negative effect, as increased costs for trucking, treating, and disposal are incurred as a result of the additional fluid.

In order to determine whether the additional water production was a result of injected or reservoir water, the chloride ion concentration in the produced fluid was examined. As the chloride concentration of both the injected and the reservoir water was known, the relative amounts of injected and reservoir water produced could be determined for any given day. This analysis was performed on a daily basis for the first 100 days after commencement of production. Figures 104 to 107 show the cumulative injection water produced over this period (expressed as a percentage of the amount injected) for each of the respective well pairs.

As can be seen from the figures, the percentage of injected water produced back over the 100 day period is similar in all wells, varying from 12 - 17%. Consistency between the well pairs is even more evident, with variances in injected water production of only 0.5 - 2%. This indicates that the increased water production is due to an increase in reservoir water production, not injected water.

There appears to be no correlation in the additive wells between surfactant concentration in the produced water samples and fluid production rates. Three of the four additive wells, as illustrated in Figures 80, 82 and 83, exhibit similar profiles for surfactant concentration found in water samples taken during the production phase. Wells 5A-3, 12-3, and 7-17 all show peak surfactant concentration in produced water occurring approximately 30-40 days after commencement of production. Well 10-17, however, shows a general trend of surfactant concentration increasing over the production period sampled (100 days after commencing production). This trend is illustrated in Figure 81. Examination of production profiles over this same period did not yield any conclusions as to how the two sets of data are related.

As the surfactant concentration was measured in the produced water only, an attempt was made to determine the amount of surfactant produced back in the water over the 100 day period following commencement of production. The amount of surfactant produced back over this period, expressed as a percentage of the amount injected, is as follows for each of the wells:

07-17-081-22 W4M	10.1%
10-17-081-22 W4M	9.2%
12-03-081-22 W4M	9.4%
5A-03-081-22 W4M	11.4%

The cumulative surfactant production in the water phase for each of the additive wells, expressed as a percentage of the amount injected, is shown in Figure 108. If the cumulative surfactant production is compared to the cumulative injection water production, a very similar trend can be noted. The percentage of surfactant recovered is approximately the same as the percentage of injection water recovered. It is interesting to note that, although all of the wells responded differently to the cyclic steam stimulation, they all appear to be very consistent with respect to surfactant and injection water recovery.

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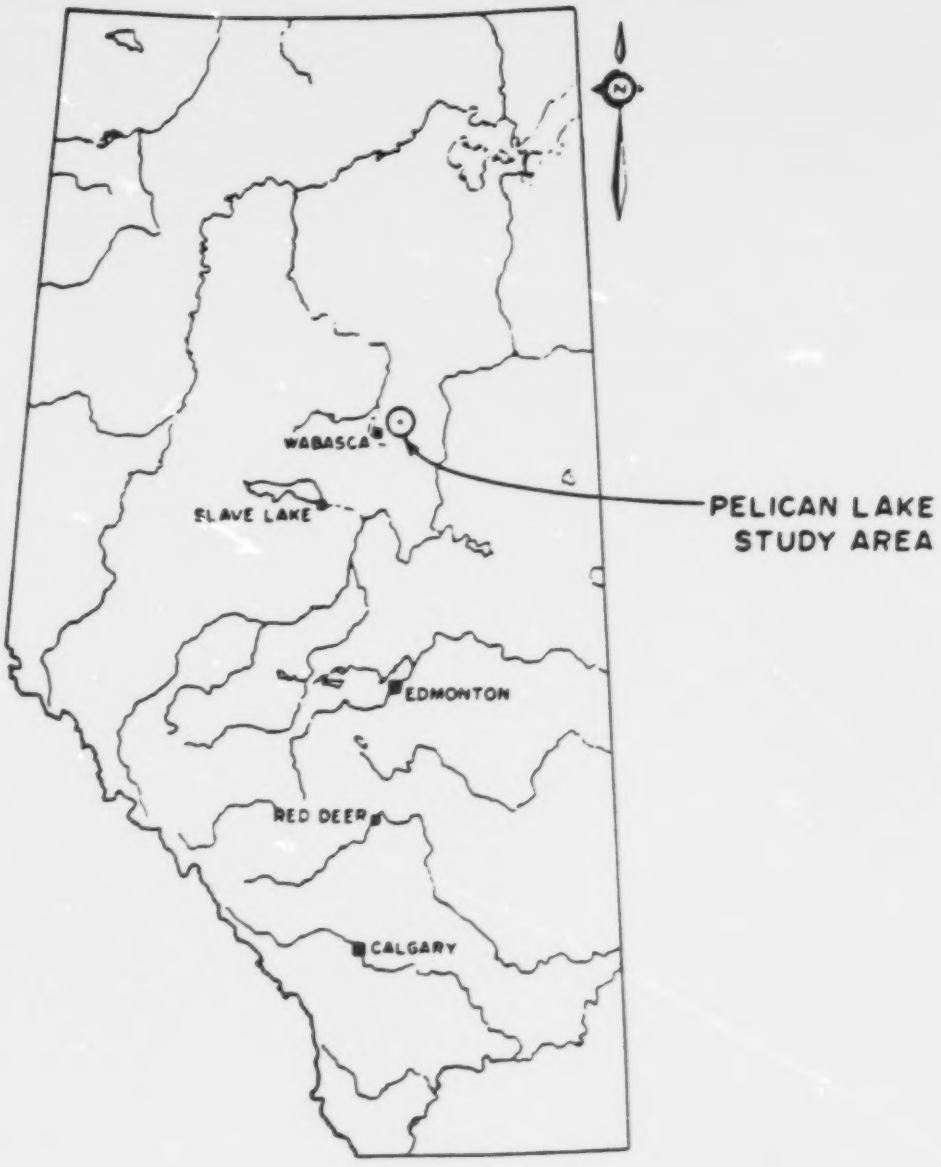
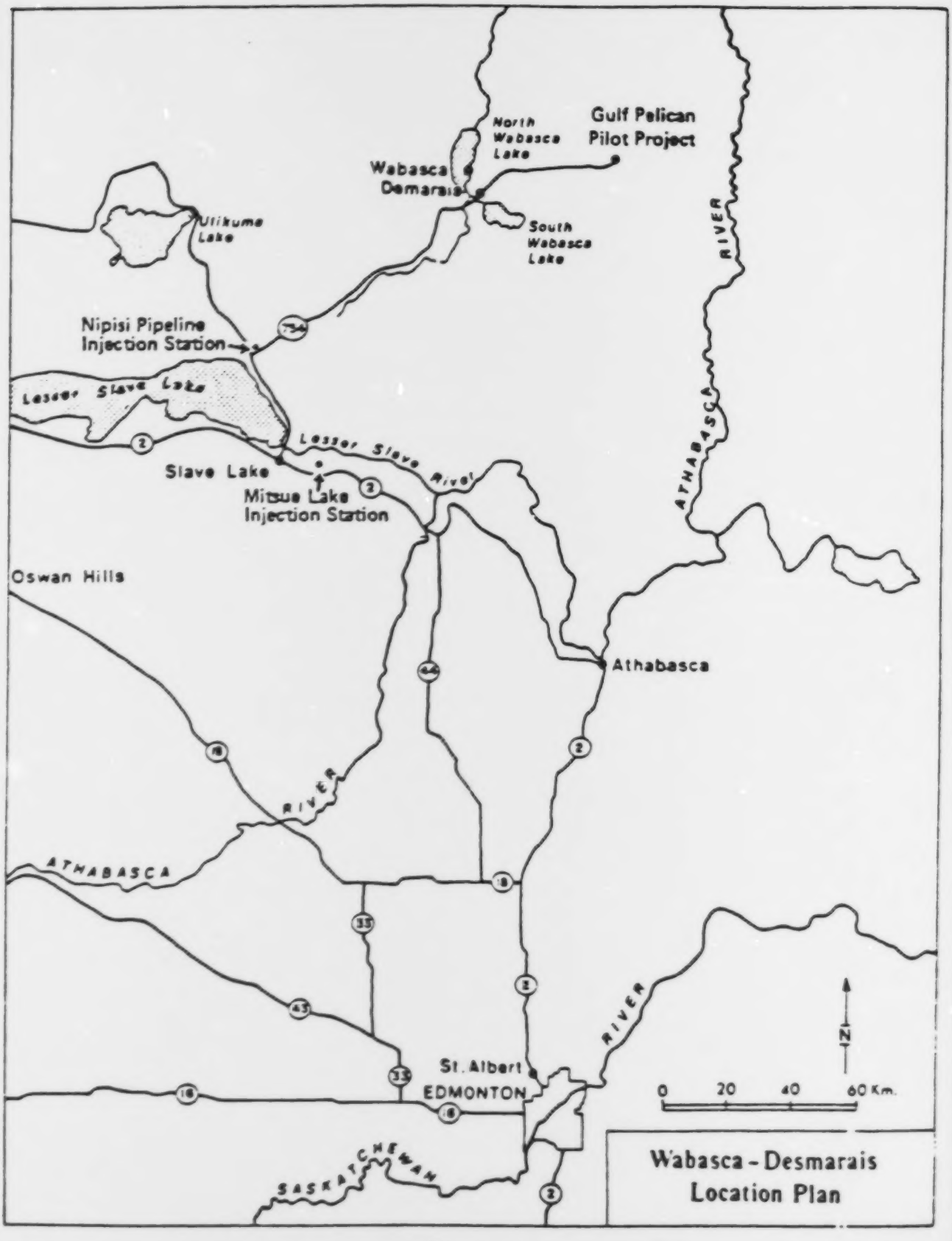
FIGURE 1



LOCATION OF PELICAN LAKE PROJECT IN ALBERTA

FIGURE 2


North Wabasca Lake
Gulf Pelican Pilot Project
Wabasca Demarais
South Wabasca Lake
Utikuma Lake
ATHABASCA RIVER
Nipisi Pipeline Injection Station
Lesser Slave Lake
Lesser Slave River
Slave Lake
Mitsue Lake Injection Station
Oswan Hills
Athabasca
ATHABASCA RIVER
St. Albert
EDMONTON
SASKATCHEWAN RIVER
N
0 20 40 60 Km.
Wabasca - Desmarais Location Plan

CORRELATION CHART FOR OIL SANDS

The Wabiskaw is a member of the Clearwater Formation of the Lower Cretaceous Mannville group. It is informally subdivided into three units called the Wabiskaw A, B and C.

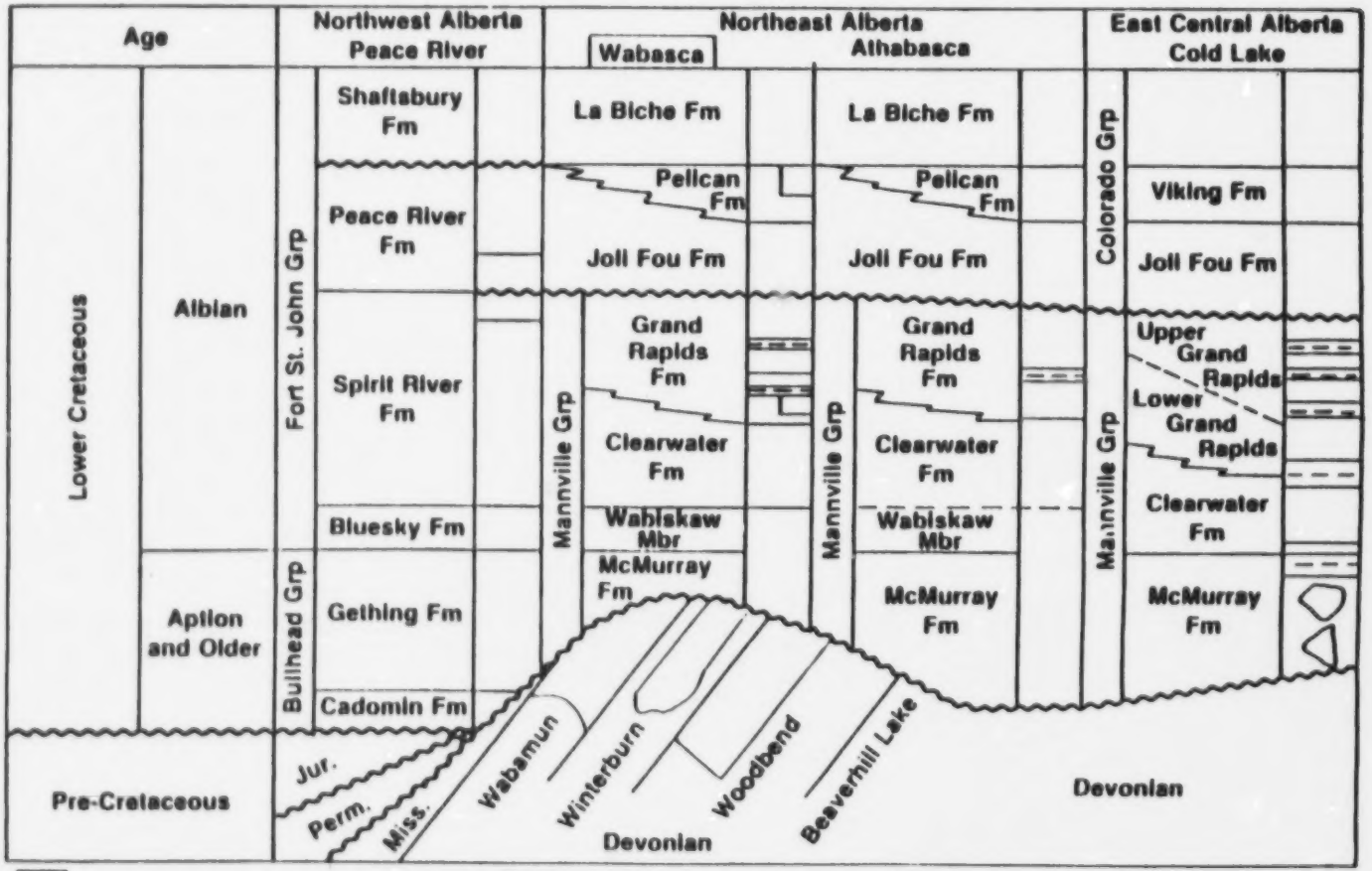


FIGURE 3

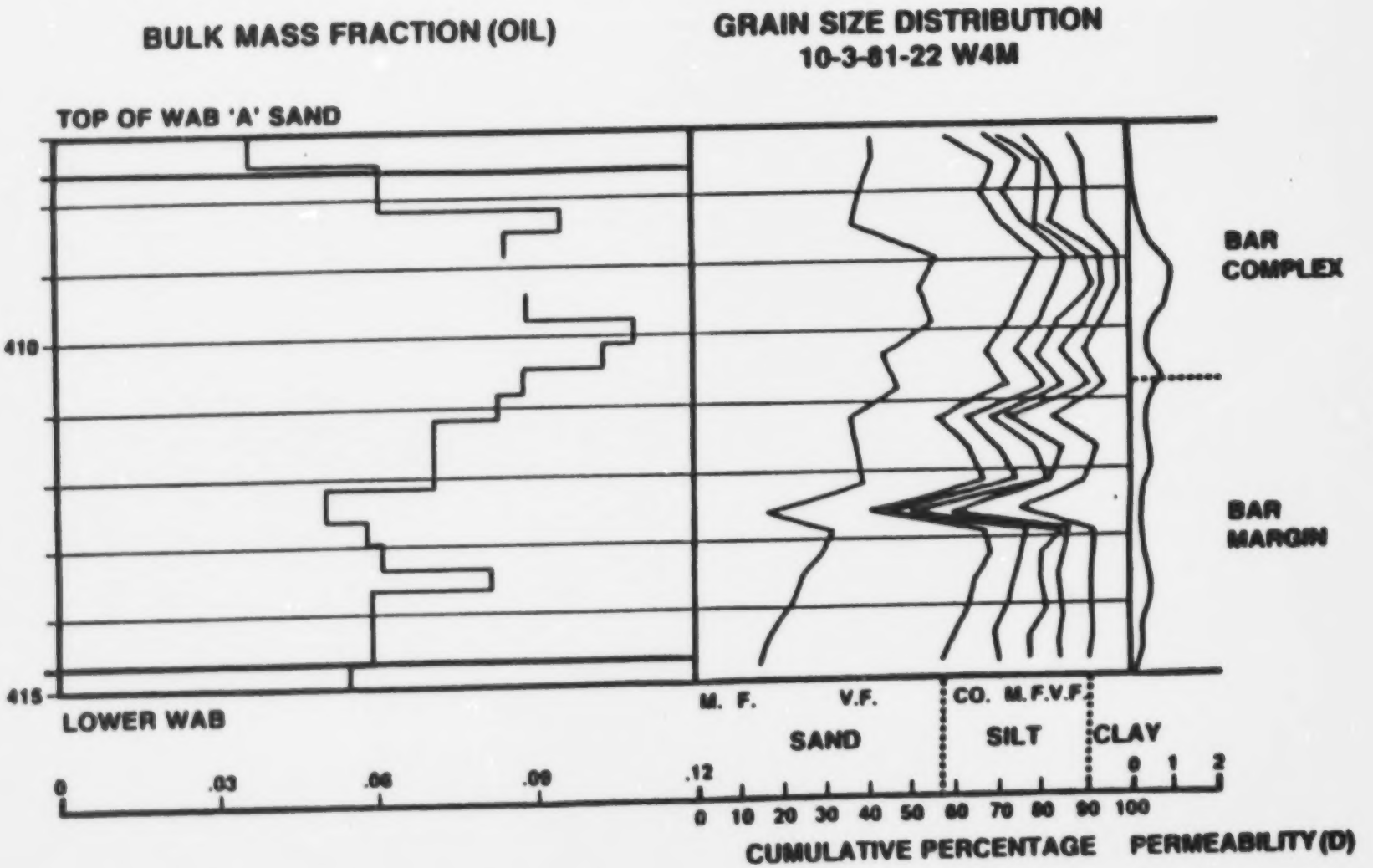
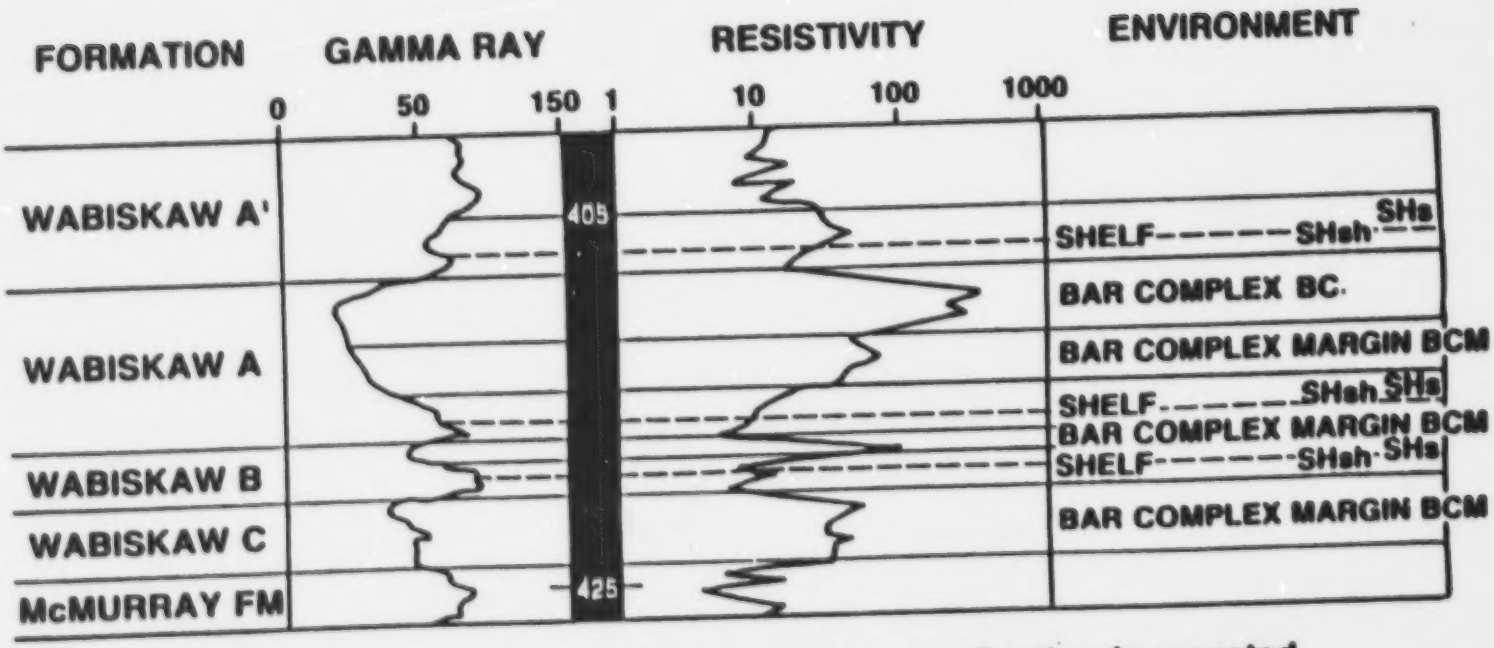

BULK MASS FRACTION (OIL)
GRAIN SIZE DISTRIBUTION
10-3-81-22 W4M
TOP OF WAB 'A' SAND
410
415
LOWER WAB
BAR COMPLEX
BAR MARGIN
M. F. V.F.
CO. M.F.V.F.
SAND
SILT
CLAY
0 .03 .06 .09 .12
0 1 2
0 10 20 30 40 50 60 70 80 90 100
CUMULATIVE PERCENTAGE
PERMEABILITY (D)

FIGURE 4

COMPOSITE LOG – WABISKAW SECTION



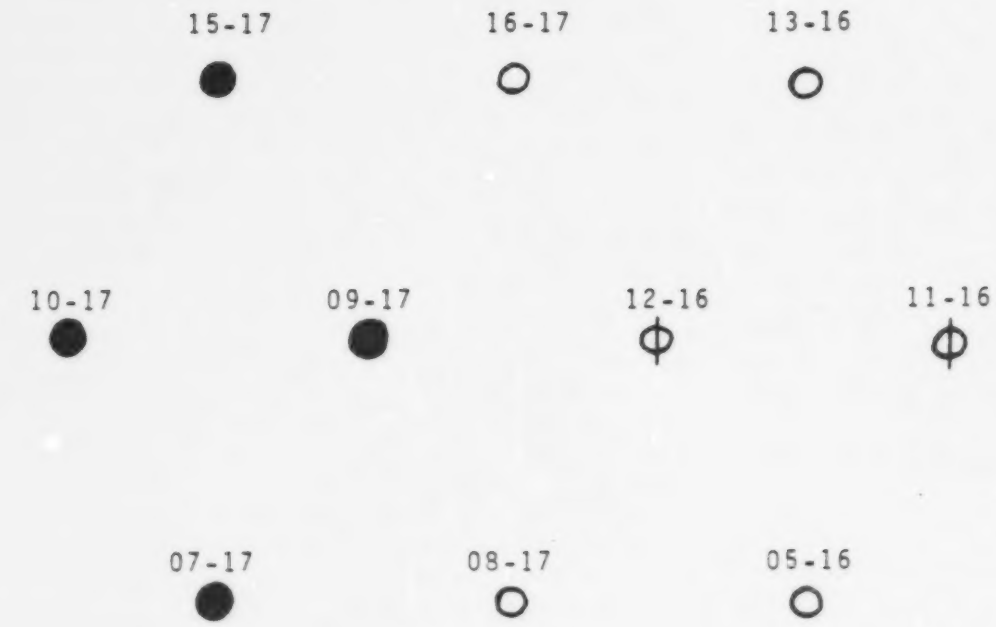
Typical stratigraphy in area around pilot site. Section is repeated three times except that no bar complex is present in the Wabiskaw B and C units.

FIGURE 5

FIGURE 6

E.M.R. STUDY - WELLS LOCATIONS

AREA I



● EMR STUDY WELLS

○ OTHER STEAMED WELLS

ϕ PRIMARY WELLS

FIGURE 7
E.M.R. STUDY - WELLS LOCATIONS

AREA II

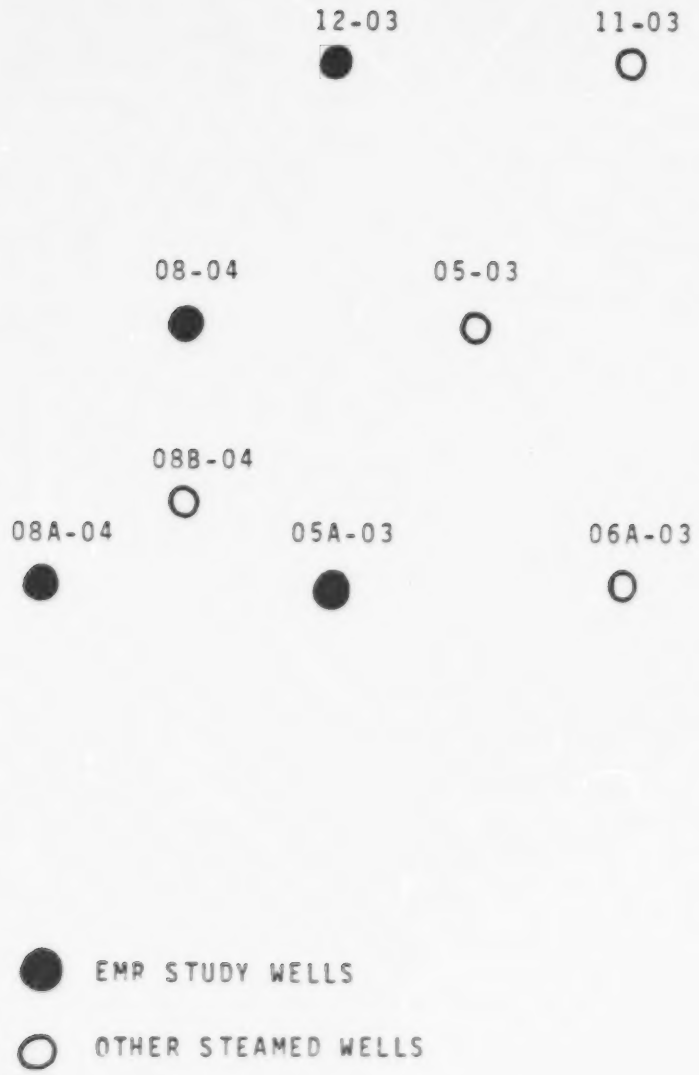
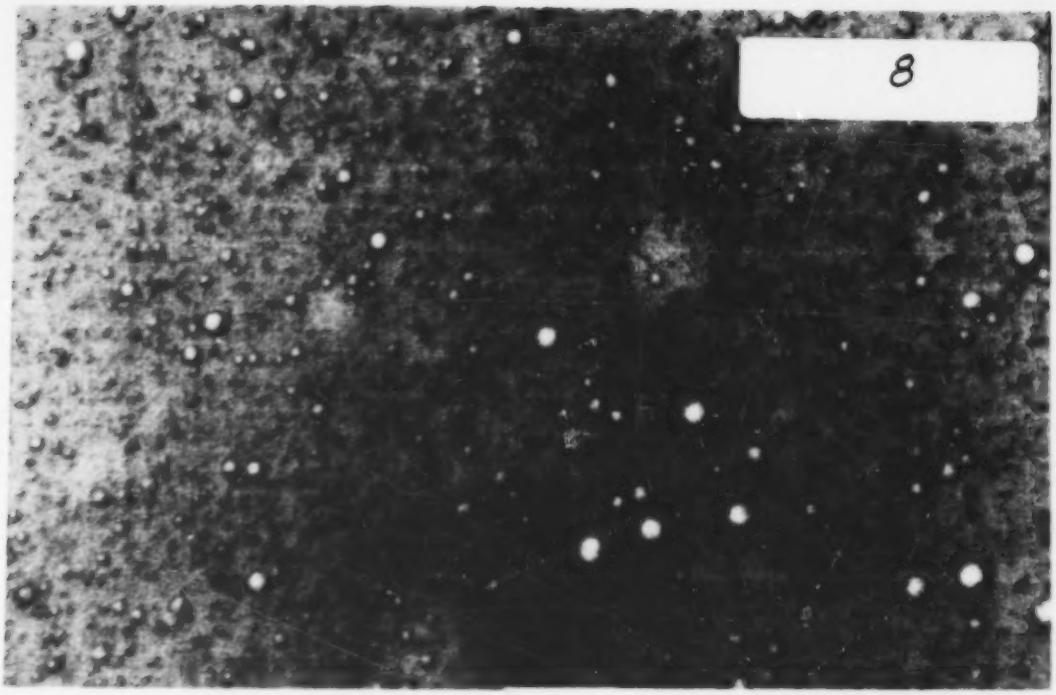


FIGURE 8

PHOTOMICROGRAPH OF PELICAN LAKE CRUDE NO CENTRIFUGATION, MAGNIFICATION 400X.

FIGURE 9

PHOTOMICROGRAPH OF PELICAN LAKE CRUDE NO CENTRIFUGATION, MAGNIFICATION 800X.


8

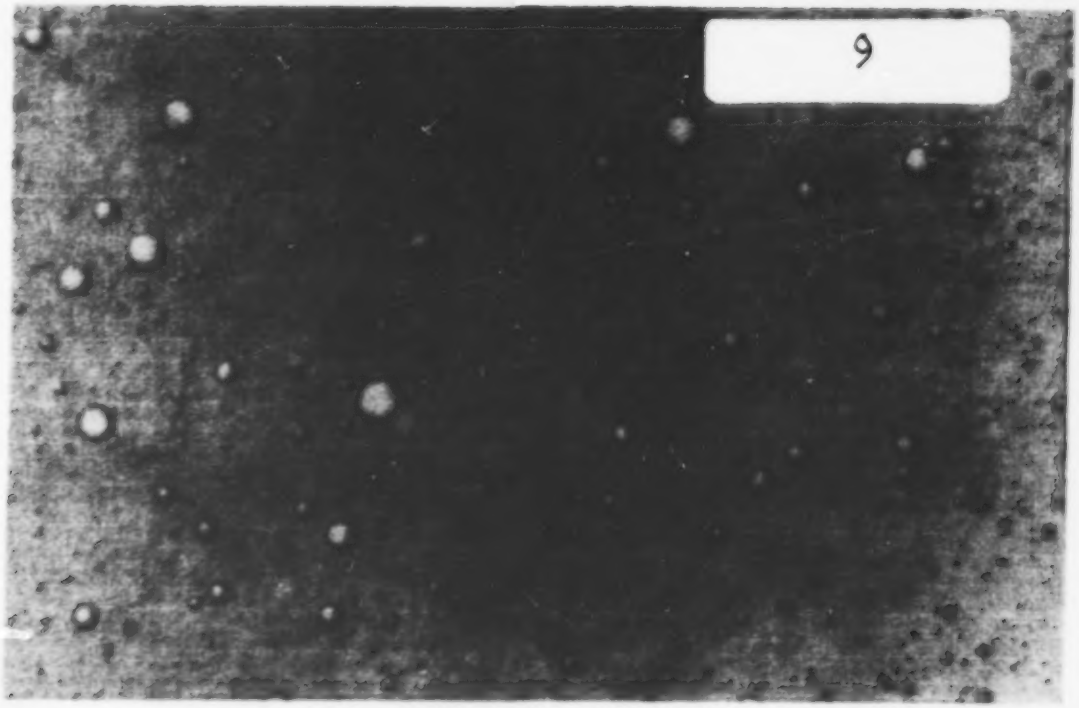
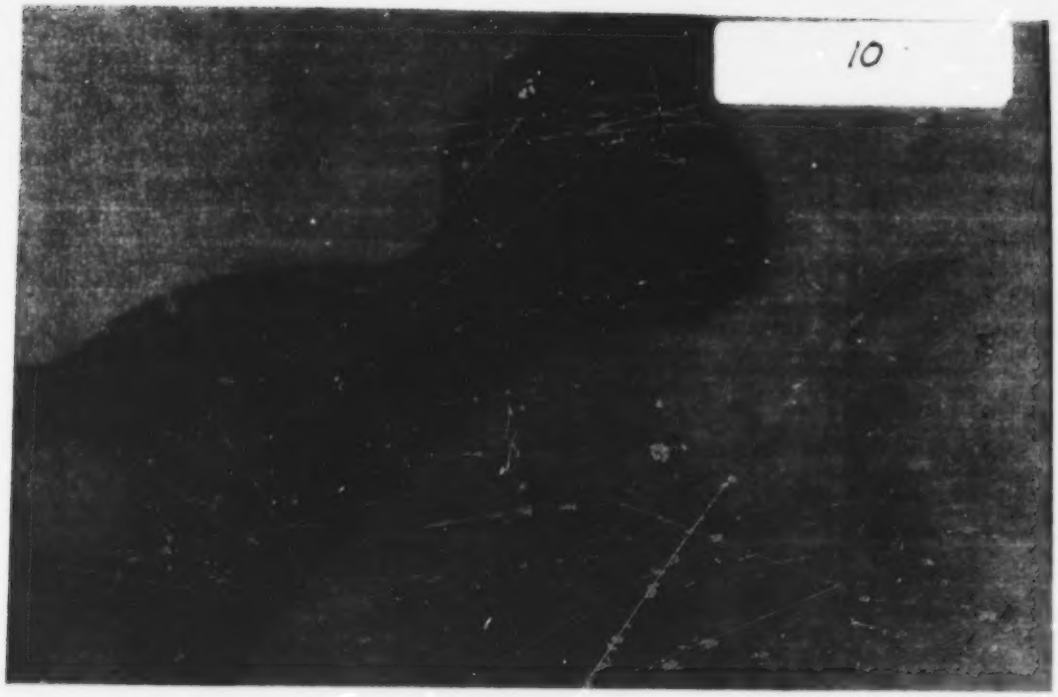

9

FIGURE 10

PHOTOMICROGRAPH OF PELICAN LAKE CRUDE MIXED WITH RESERVOIR WATER, MAGNIFICATION 400X.

FIGURE 11

PHOTOMICROGRAPH OF PELICAN LAKE CRUDE MIXED WITH RESERVOIR WATER, MAGNIFICATION 800X.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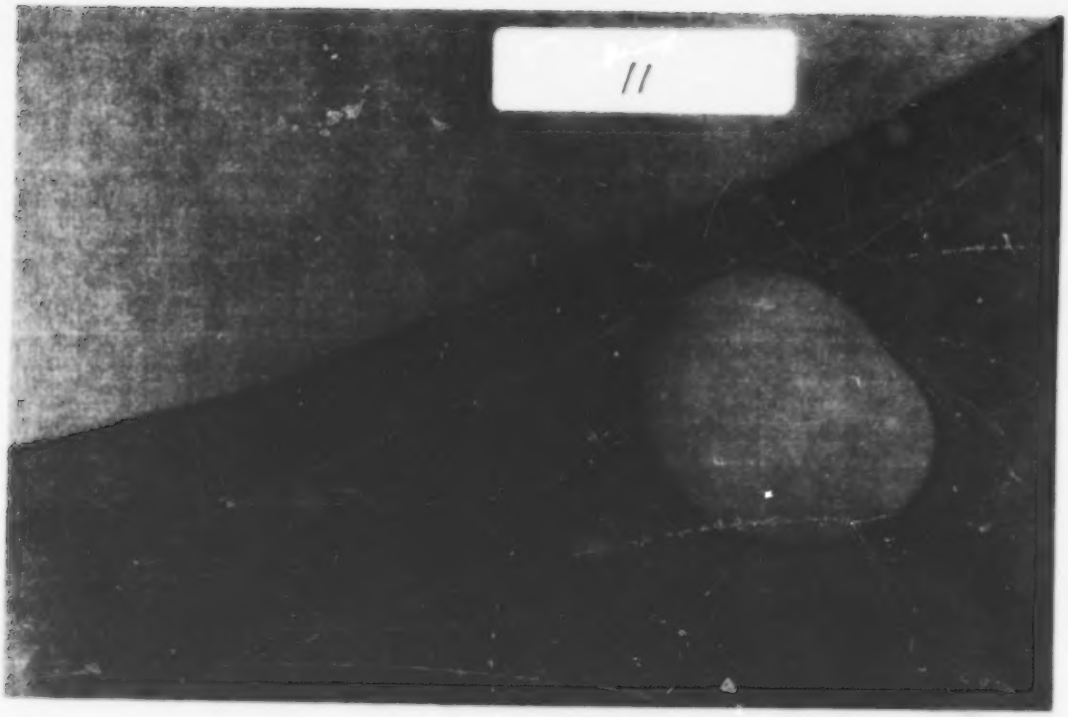
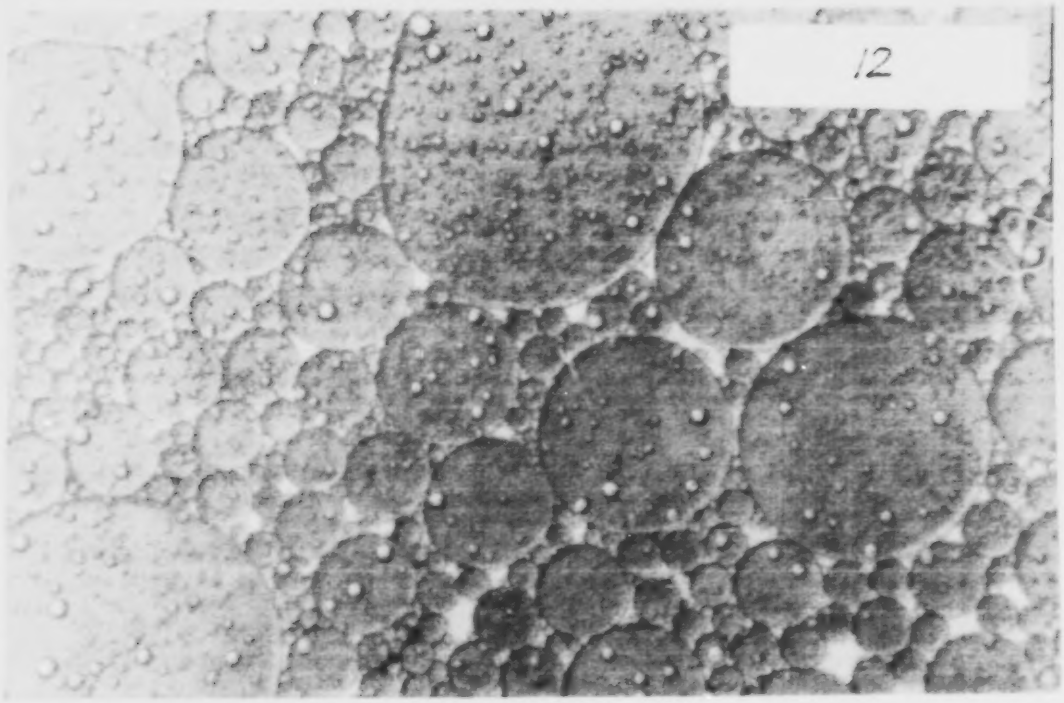

11

FIGURE 12

PHOTOMICROGRAPH OF PELICAN LAKE CRUDE MIXED WITH BOILER CONDENSATE, MAGNIFICATION 400X.

FIGURE 13

PHOTOMICROGRAPH OF PELICAN LAKE CRUDE MIXED WITH BOILER CONDENSATE, MAGNIFICATION 800X.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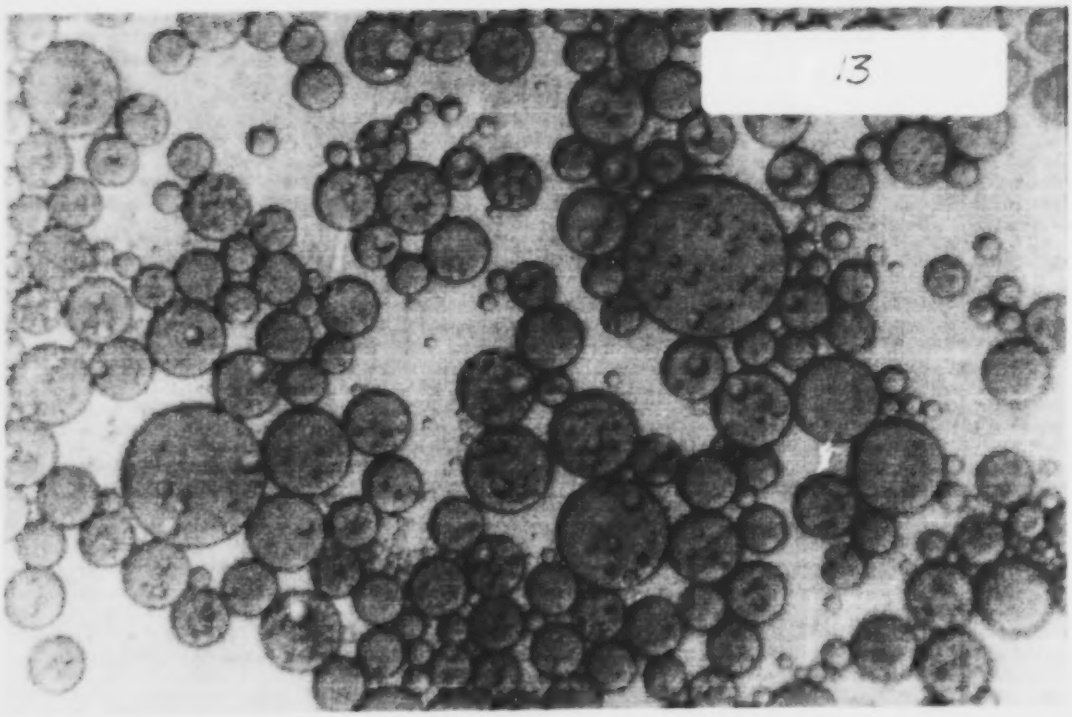
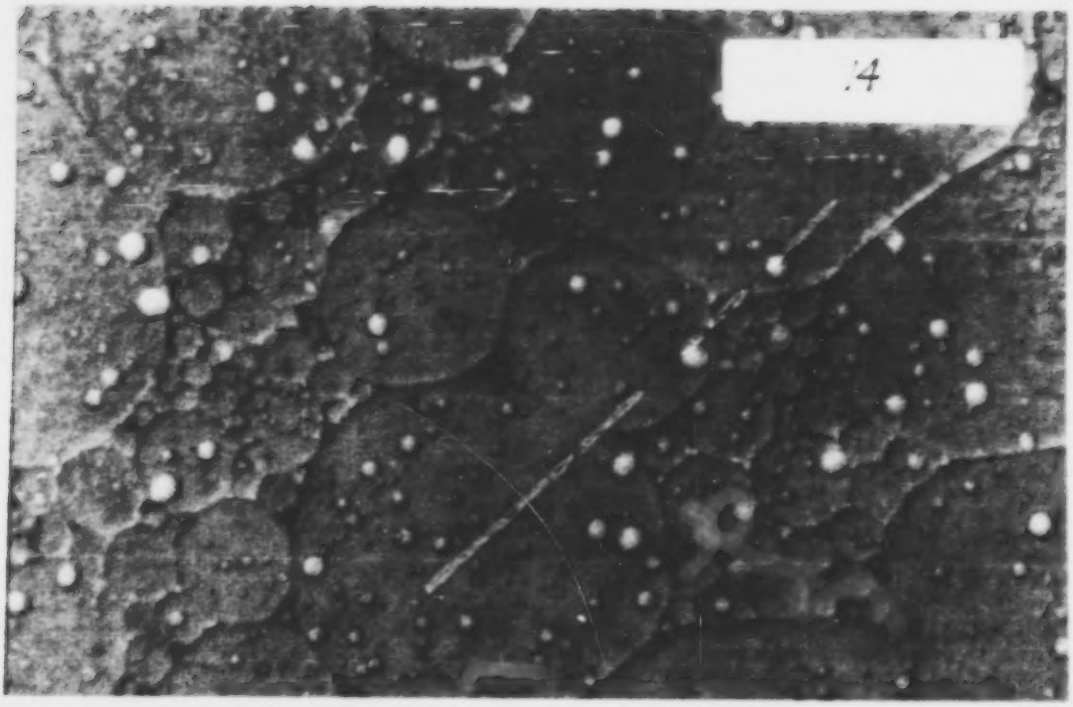

13

FIGURE 14

PHOTOMICROGRAPH OF PELICAN LAKE CRUDE MIXED WITH BOILER CONDENSATE + 600 PPM SUNTECH IV-FA, MAGNIFICATION 400X.

FIGURE 15

PHOTOMICROGRAPH OF PELICAN LAKE CRUDE MIXED WITH BOILER CONDENSATE + 600 PPM SUNTECH IV-FA, MAGNIFICATION 800X.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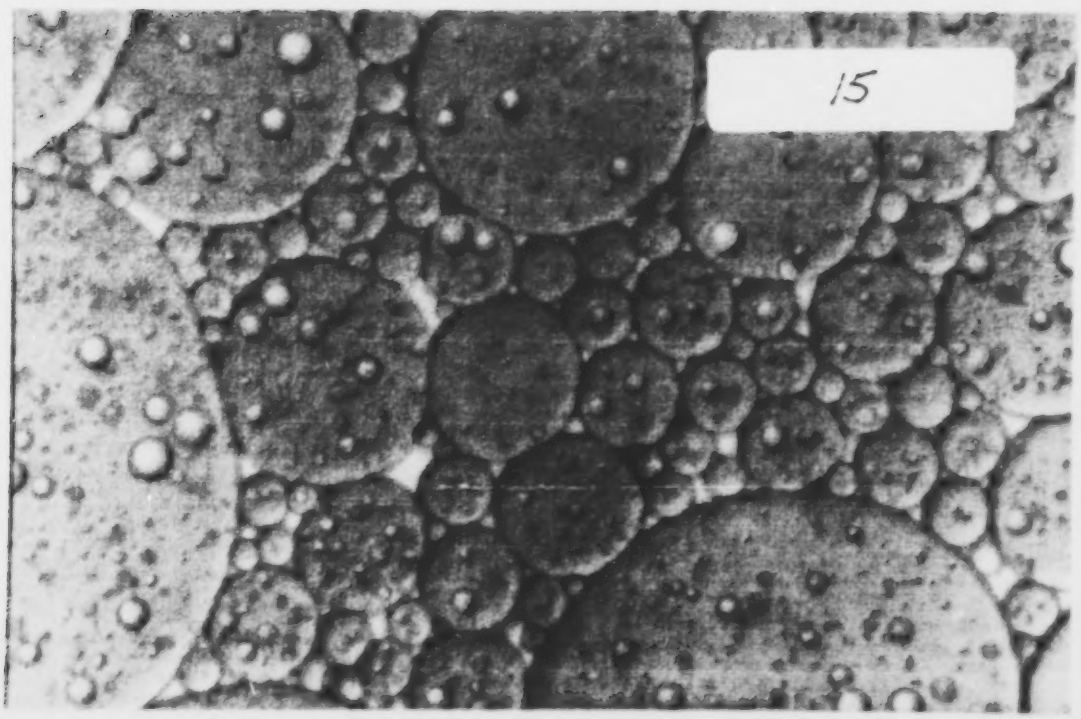
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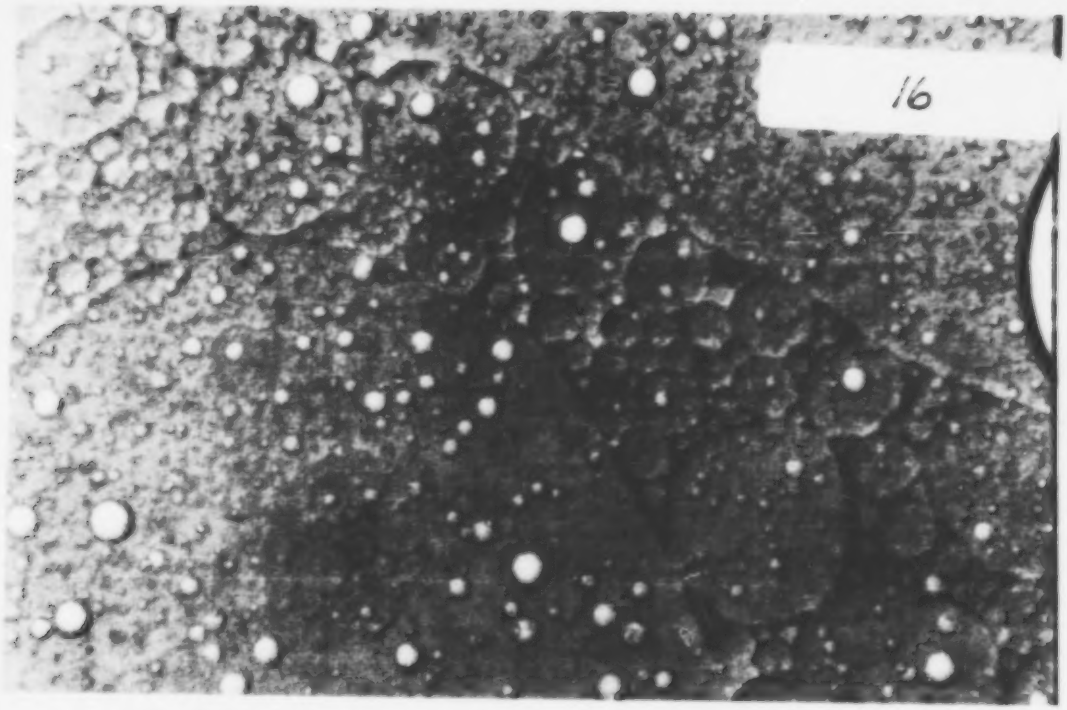
FIGURE 16

PHOTOMICROGRAPH OF PELICAN LAKE CRUDE MIXED WITH BOILER CONDENSATE + 600 PPM SHELL LTS 18, MAGNIFICATION 400X.

FIGURE 17

PHOTOMICROGRAPH OF PELICAN LAKE CRUDE MIXED WITH BOILER CONDENSATE + 600 PPM SHELL LTS 18, MAGNIFICATION 800X.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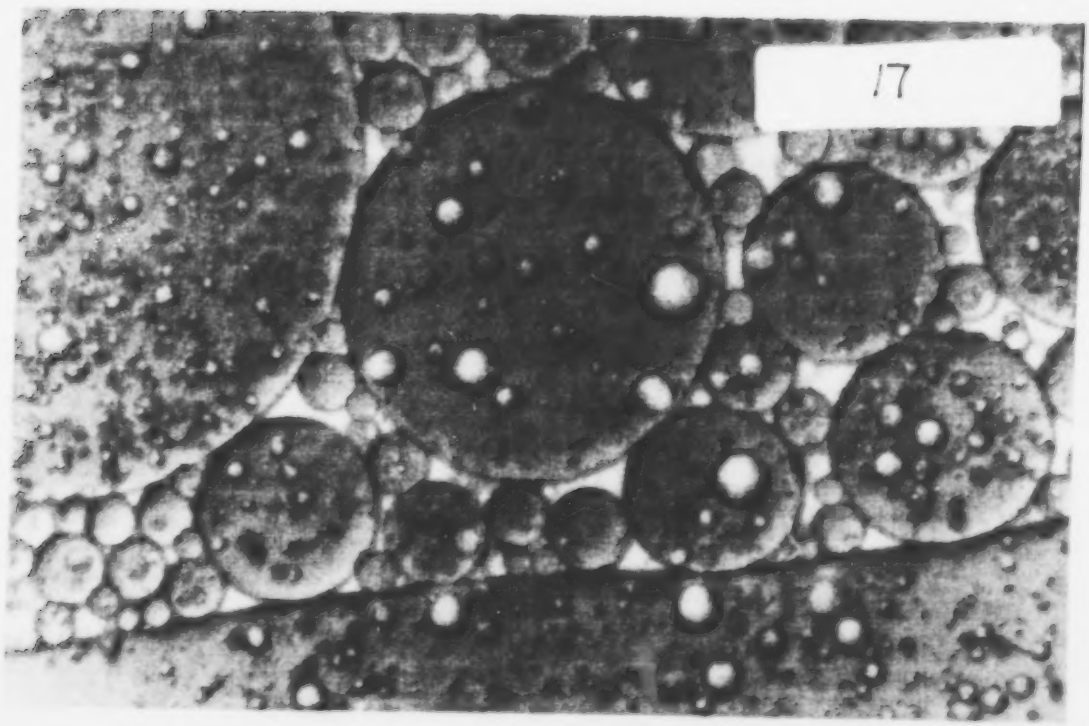

17

FIGURE 18

PHOTOMICROGRAPH OF PELICAN LAKE CRUDE MIXED WITH RESERVOIR WATER + 600 PPM SUNTECH IV-FA, MAGNIFICATION 400X.

FIGURE 19

PHOTOMICROGRAPH OF PELICAN LAKE CRUDE MIXED WITH RESERVOIR WATER + 600 PPM SUNTECH IV-FA, MAGNIFICATION 800X.

18

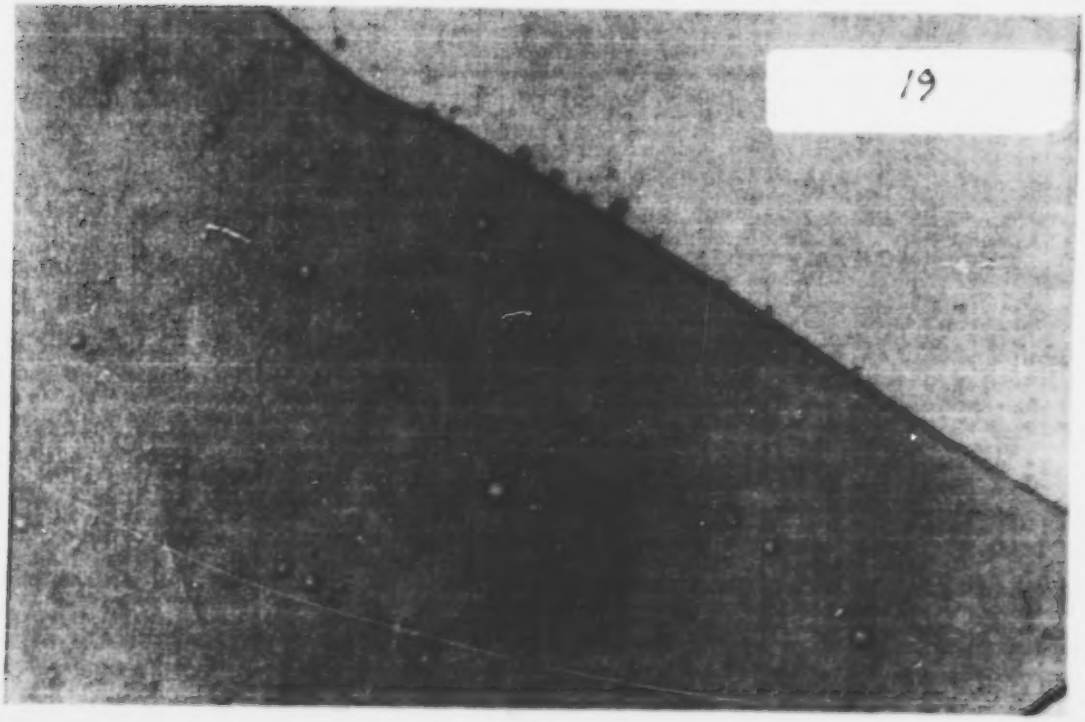
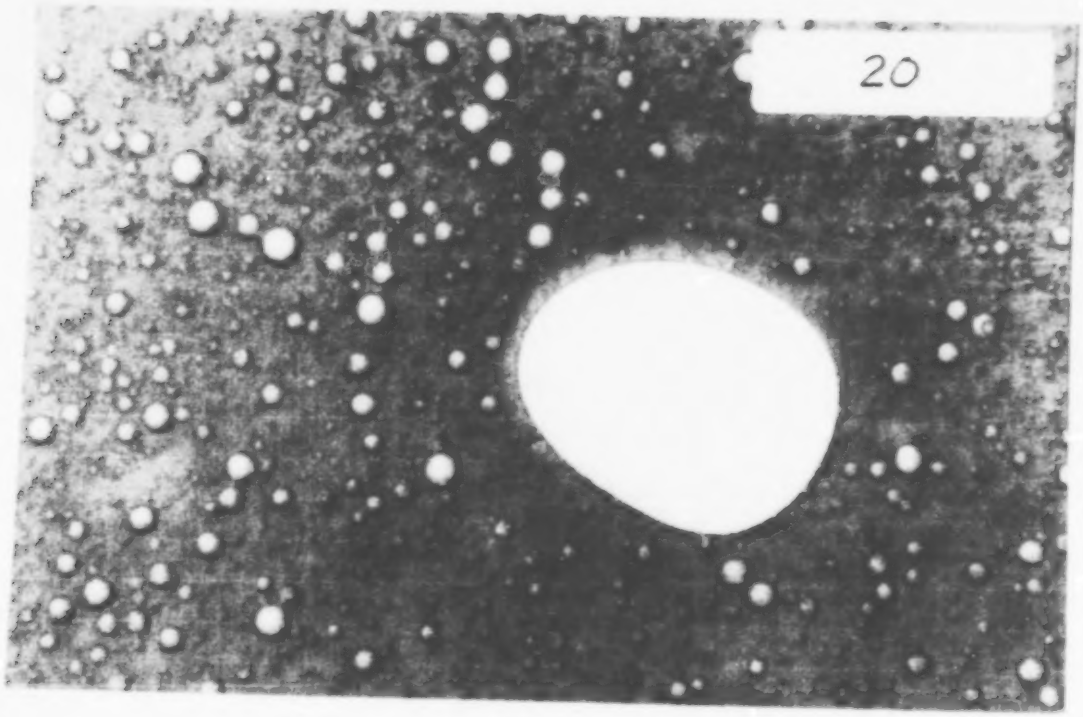

19

FIGURE 20

PHOTOMICROGRAPH OF PELICAN LAKE CRUDE MIXED WITH RESERVOIR WATER + 600 PPM SHELL LTS 18, MAGNIFICATION 400X.

FIGURE 21

PHOTOMICROGRAPH OF PELICAN LAKE CRUDE MIXED WITH RESERVOIR WATER + 600 PPM SHELL LTS 18, MAGNIFICATION 800X.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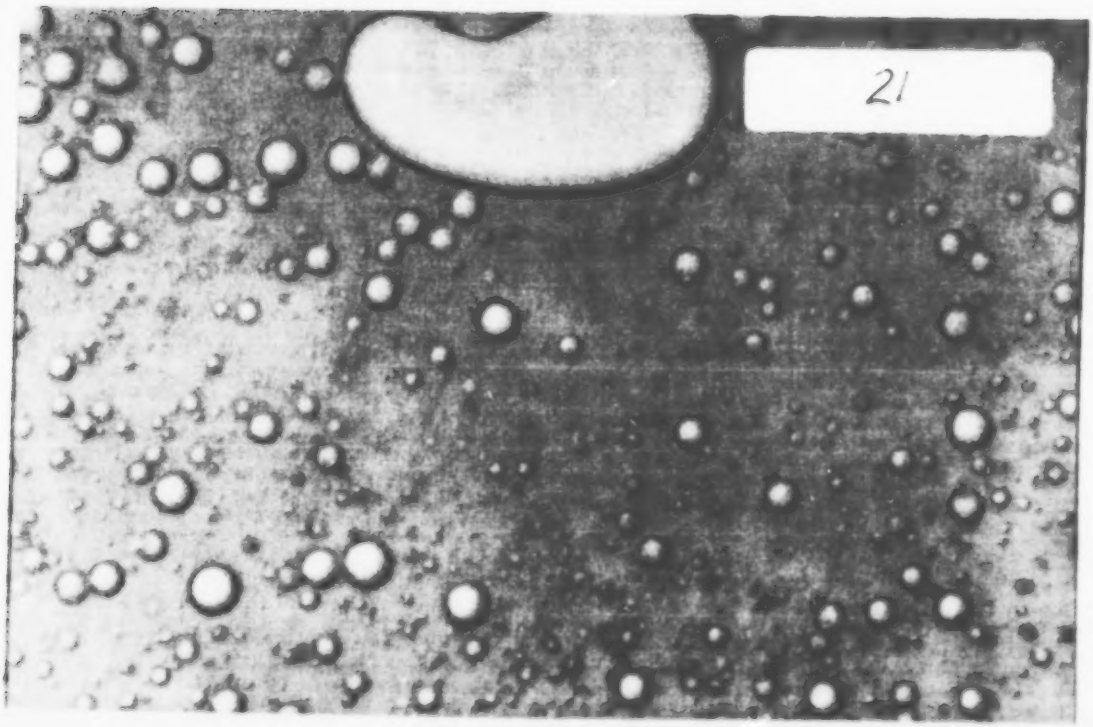
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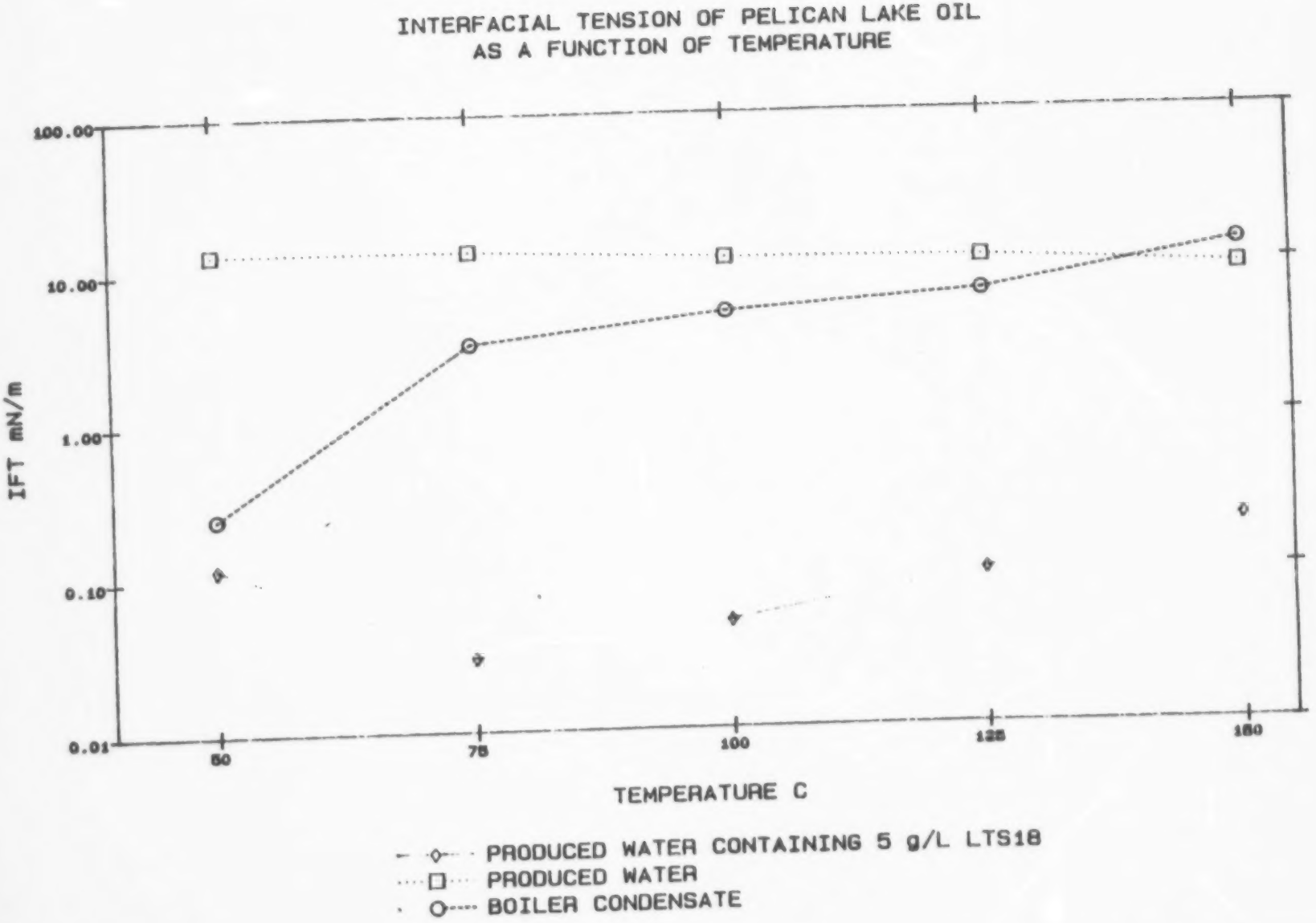
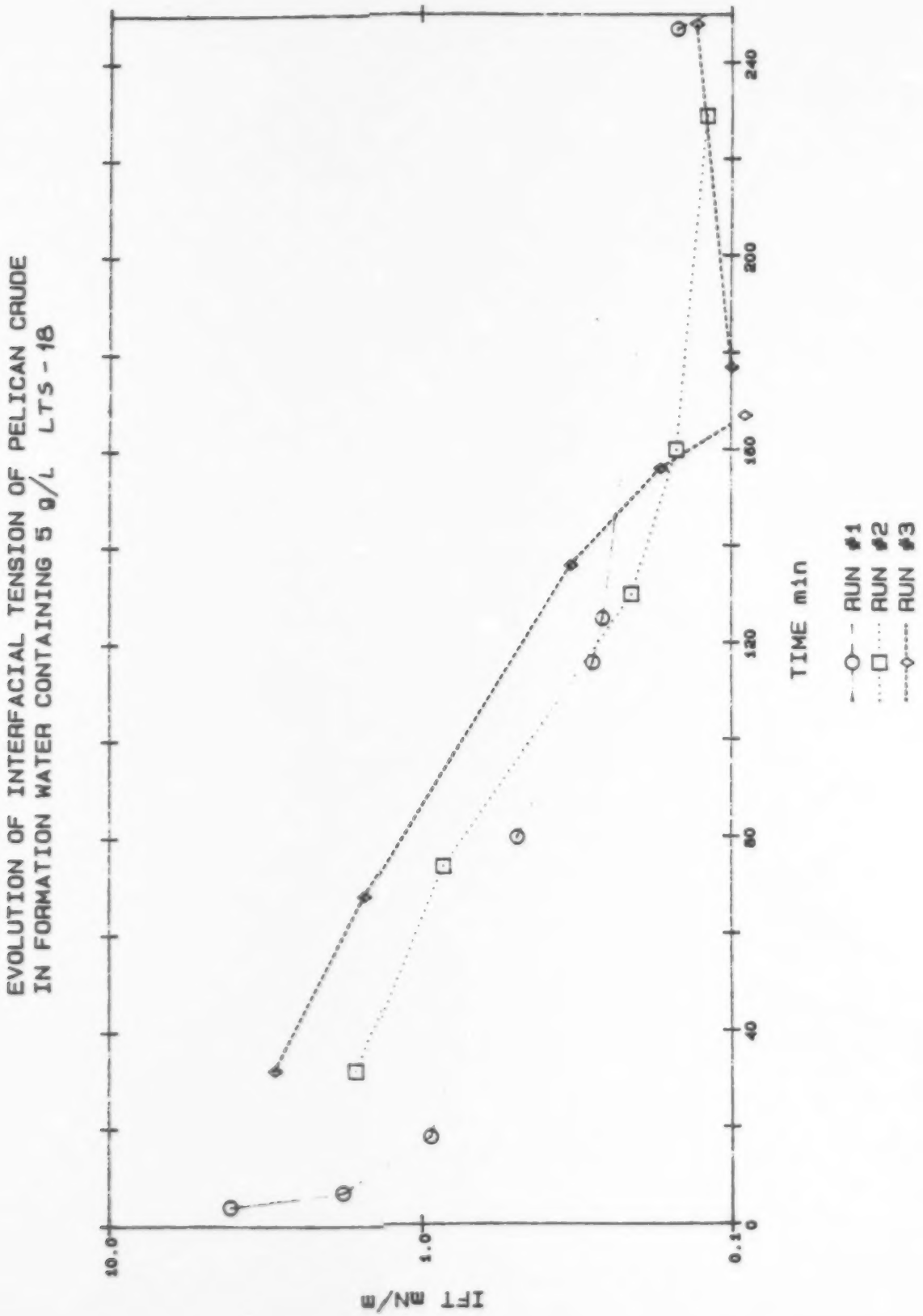

INTERFACIAL TENSION OF PELICAN LAKE OIL
AS A FUNCTION OF TEMPERATURE
100.00
10.00
1.00
0.10
0.01
IFT mN/m
50
75
100
125
150
TEMPERATURE C
PRODUCED WATER CONTAINING 5 g/L LTS18
PRODUCED WATER
BOILER CONDENSATE

FIGURE 22

FIGURE 23


EVOLUTION OF INTERFACIAL TENSION OF PELICAN CRUDE
IN FORMATION WATER CONTAINING 5 g/L LTS-18
IFT mN/m
10.0
1.0
0.1
0
40
80
120
160
200
240
TIME min
RUN #1
RUN #2
RUN #3

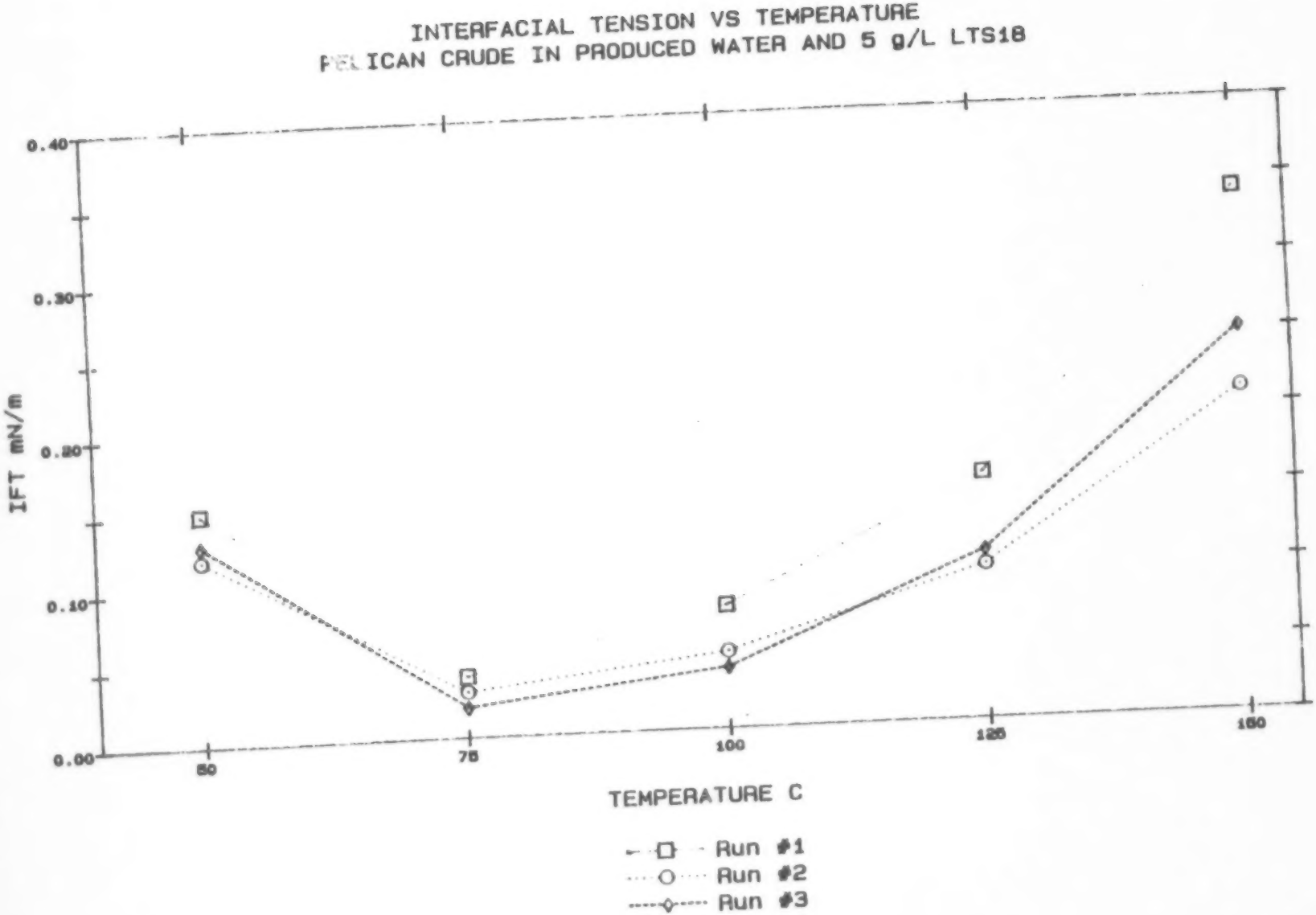

INTERFACIAL TENSION VS TEMPERATURE
PELICAN CRUDE IN PRODUCED WATER AND 5 g/L LTS18
IFT mN/m
0.40
0.30
0.20
0.10
0.00
50
75
100
125
150
TEMPERATURE C
Run #1
Run #2
Run #3

FIGURE 24

FIGURE 25

INTERFACIAL TENSION VERSUS TEMPERATURE
PELICAN CRUDE IN PRODUCED WATER
CONTAINING 5 g/L SURFACTANT

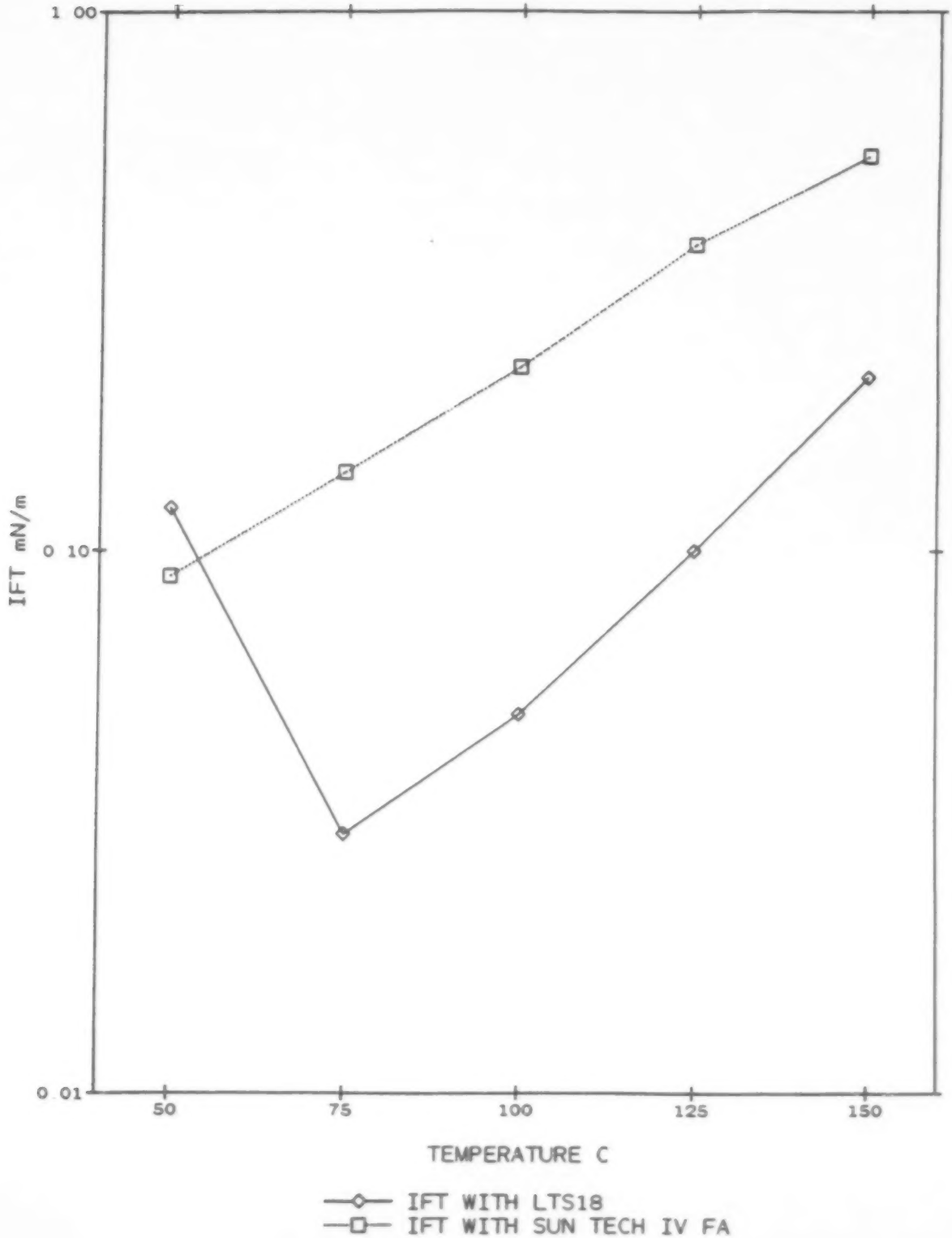


FIGURE 26

INTERFACIAL TENSION OF PELICAN LAKE OIL
IN PRODUCED WATER CONTAINING SUN TECH FA

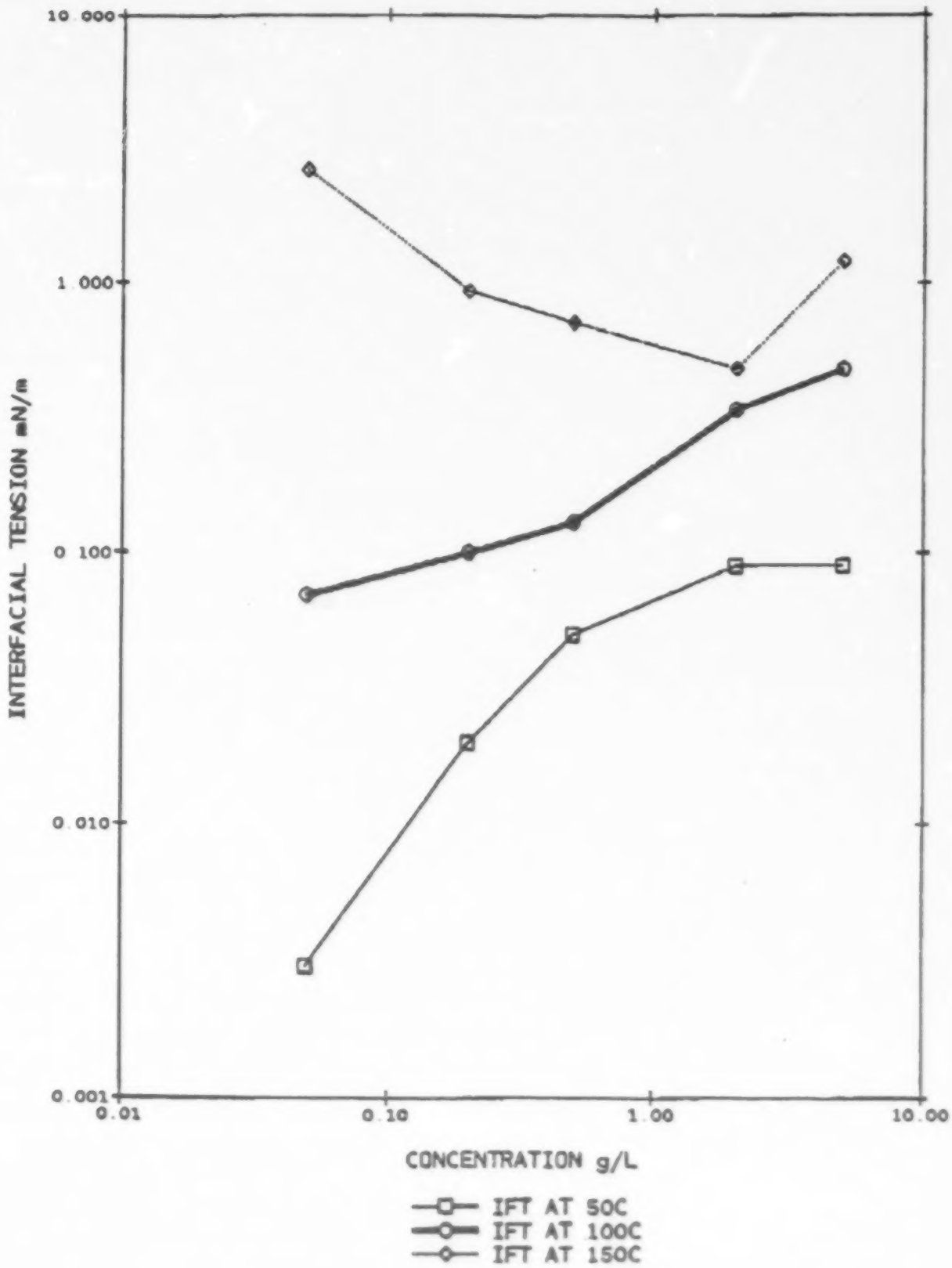
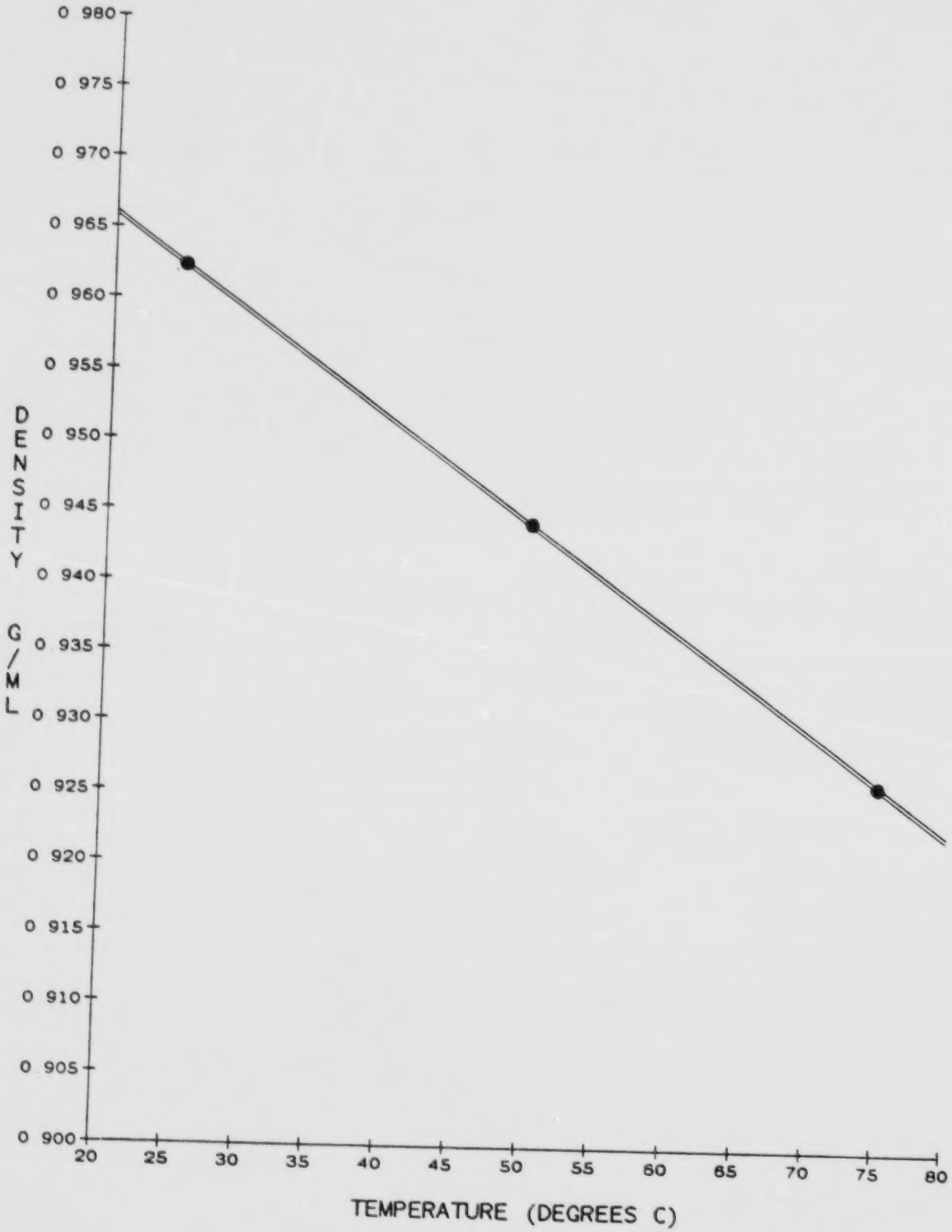


FIGURE 27

DENSITY OF SAMPLE NO. 1304 5A-3 GULF PELICAN LAKE DEWATERED BY ULTRACENTRIFUGATION AT APPROXIMATELY 400,000 G FOR 1/2 HOURS.



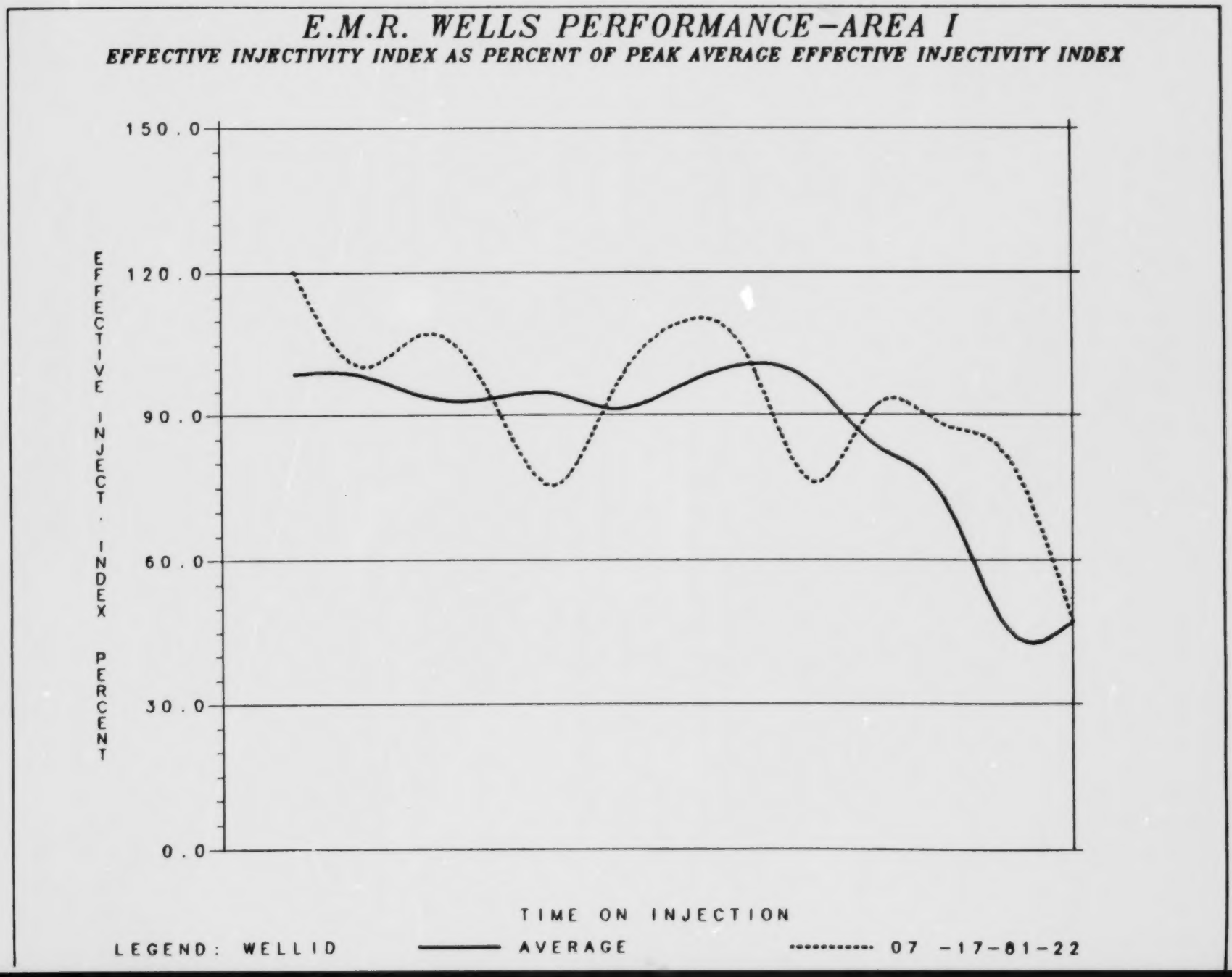

E.M.R. WELLS PERFORMANCE-AREA I
EFFECTIVE INJECTIVITY INDEX AS PERCENT OF PEAK AVERAGE EFFECTIVE INJECTIVITY INDEX
150.0
120.0
90.0
60.0
30.0
0.0
EFFECTIVE INJECT. INDEX PERCENT
TIME ON INJECTION
LEGEND: WELLID
AVERAGE
07-17-81-22

FIGURE 28

E.M.R. WELLS PERFORMANCE-AREA I

EFFECTIVE INJECTIVITY INDEX AS PERCENT OF PEAK AVERAGE EFFECTIVE INJECTIVITY INDEX

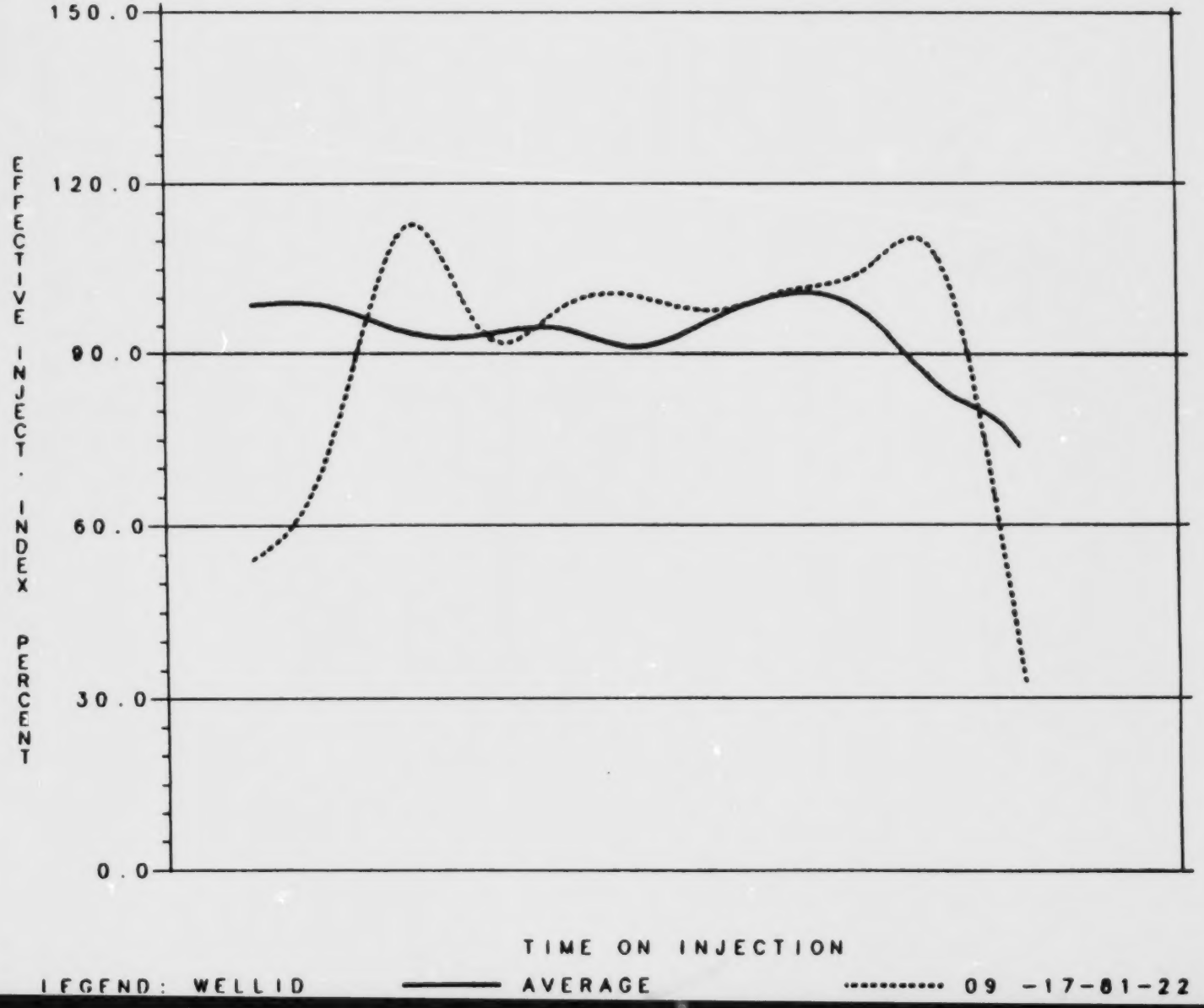


FIGURE 29

E.M.R. WELLS PERFORMANCE-AREA I

EFFECTIVE INJECTIVITY INDEX AS PERCENT OF PEAK AVERAGE EFFECTIVE INJECTIVITY INDEX

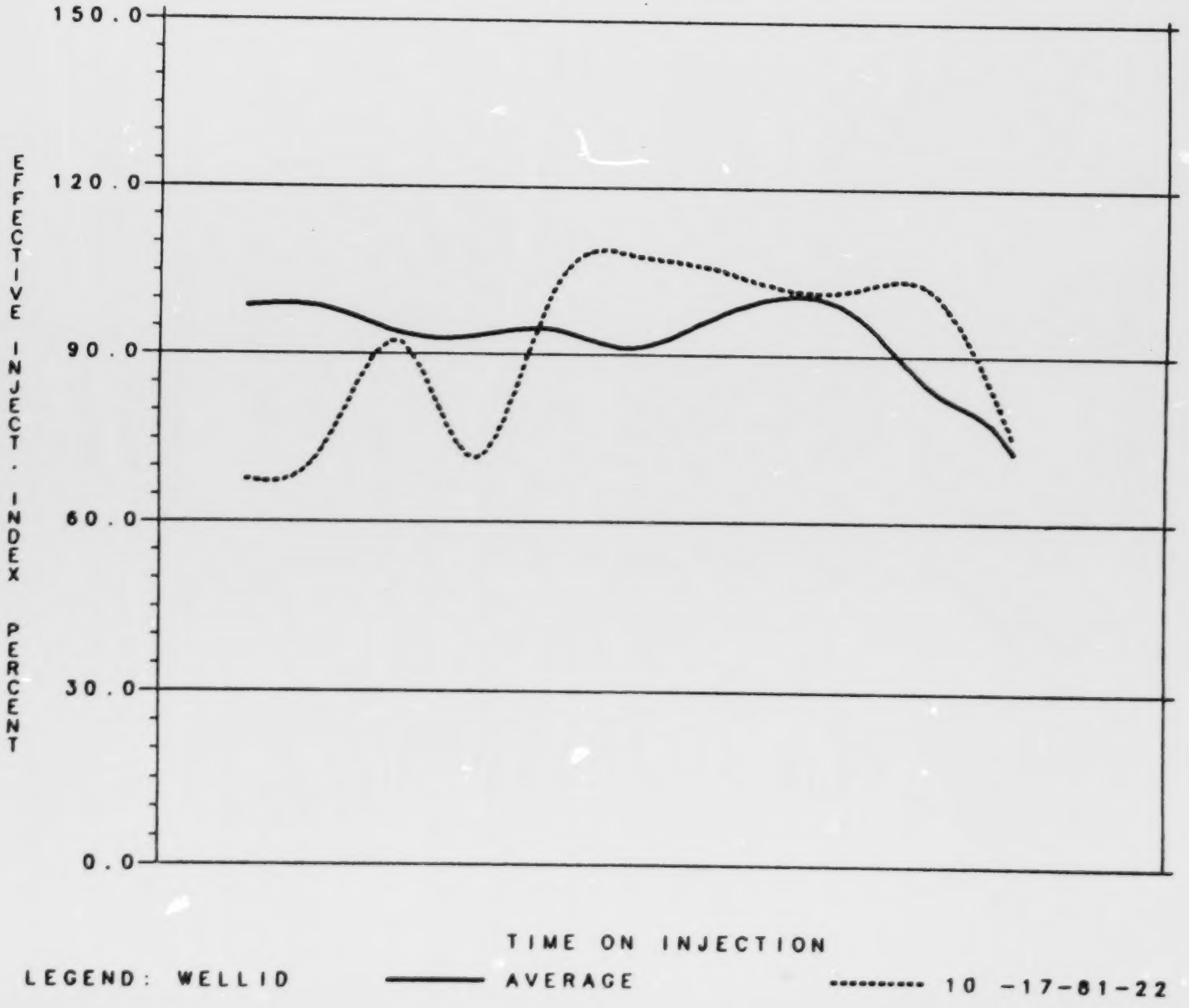


FIGURE 30

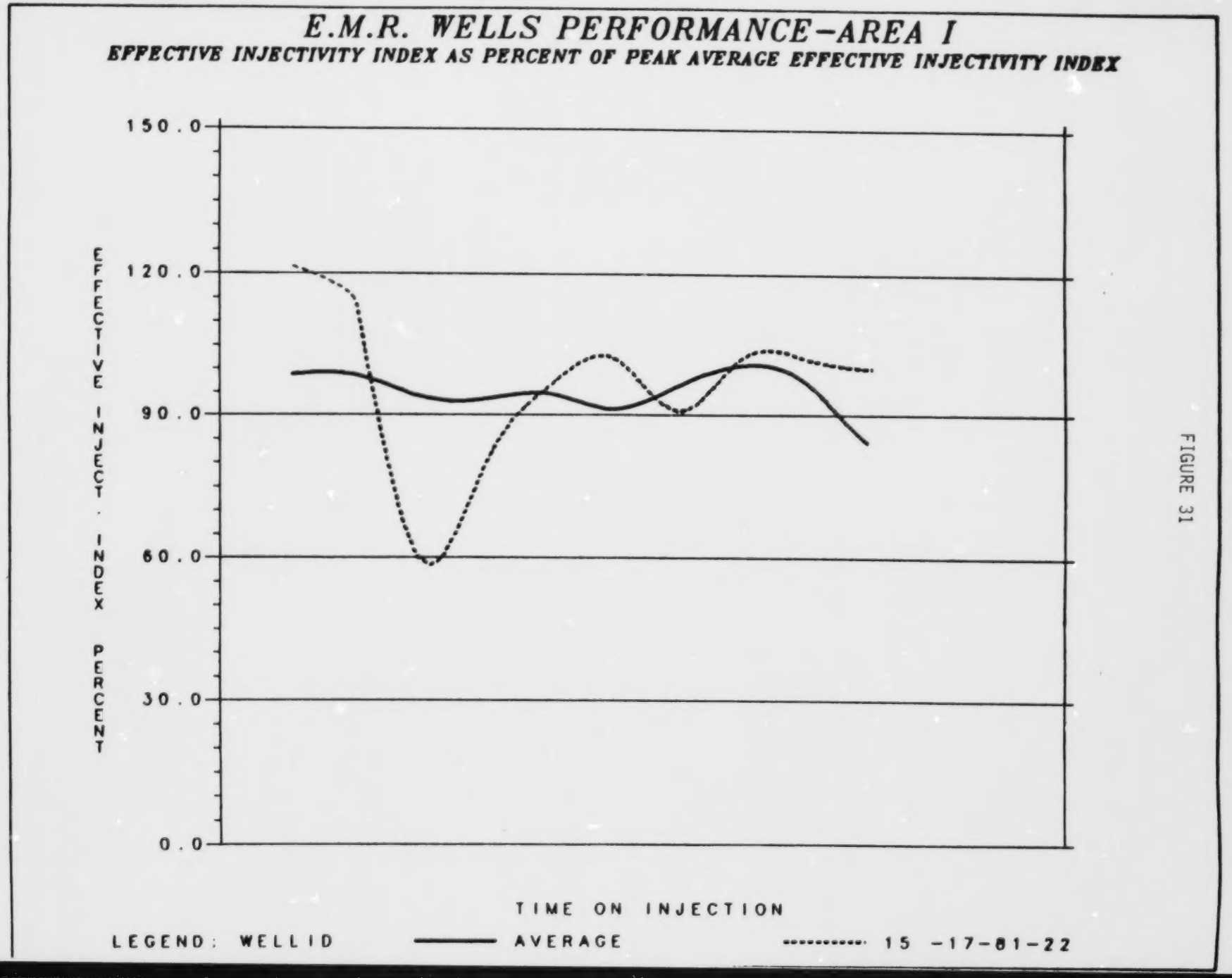

E.M.R. WELLS PERFORMANCE-AREA I
EFFECTIVE INJECTIVITY INDEX AS PERCENT OF PEAK AVERAGE EFFECTIVE INJECTIVITY INDEX
150.0
120.0
90.0
60.0
30.0
0.0
EFFECTIVE INJECT. INDEX PERCENT
TIME ON INJECTION
LEGEND: WELLID
AVERAGE
15 -17-81-22

FIGURE 31

E.M.R. WELLS PERFORMANCE-AREA II

EFFECTIVE INJECTIVITY INDEX AS PERCENT OF PEAK AVERAGE EFFECTIVE INJECTIVITY INDEX

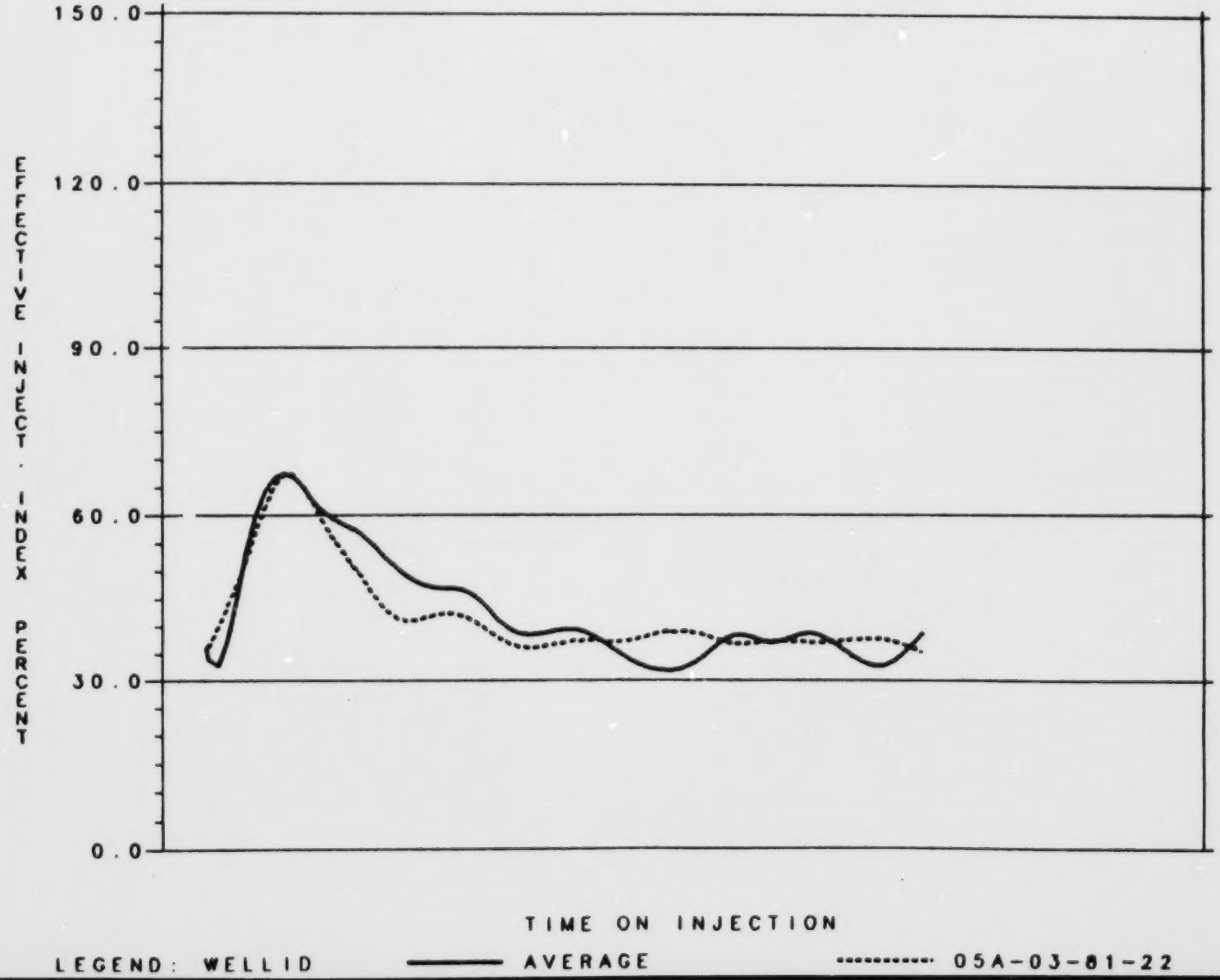


FIGURE 32

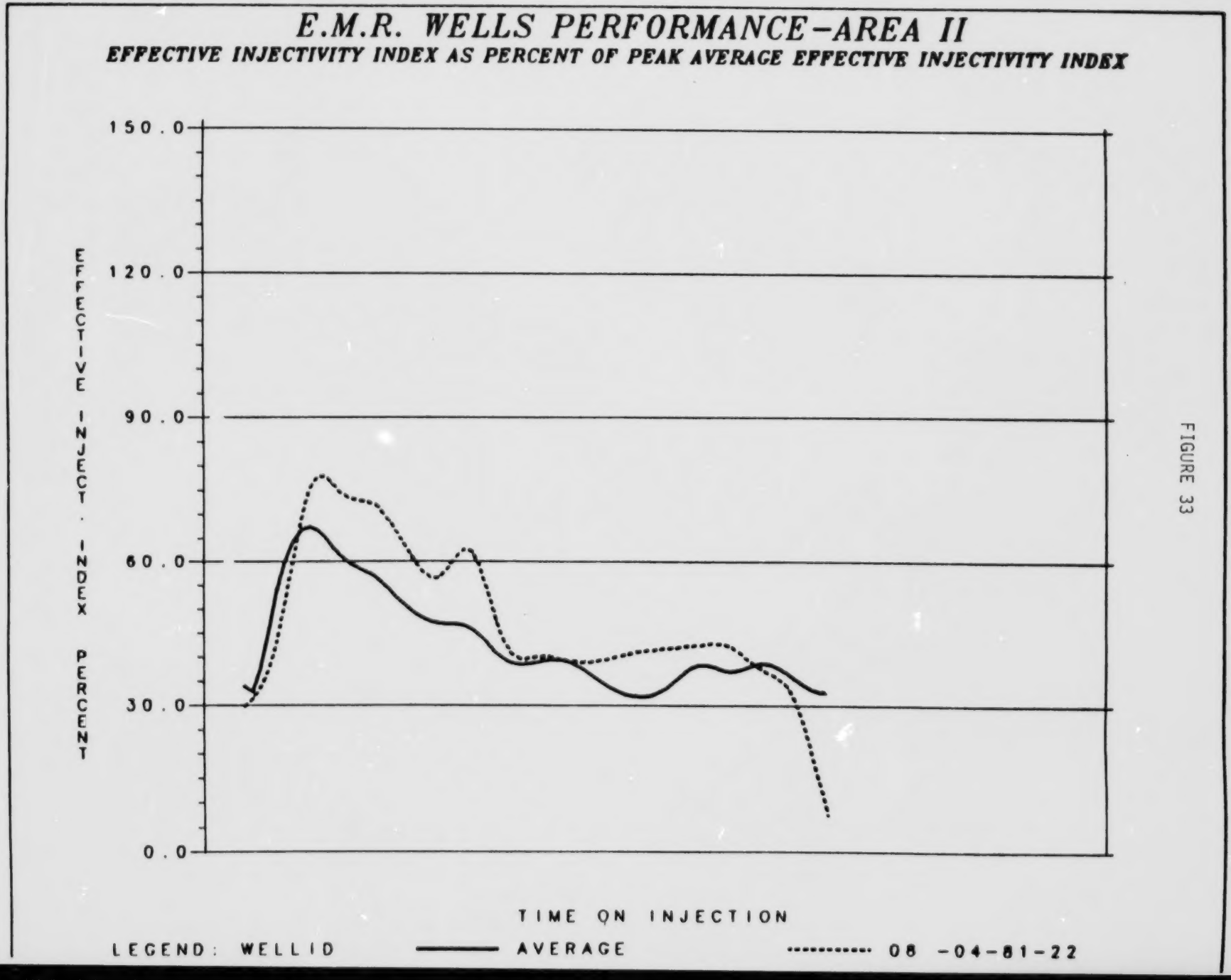

E.M.R. WELLS PERFORMANCE-AREA II
EFFECTIVE INJECTIVITY INDEX AS PERCENT OF PEAK AVERAGE EFFECTIVE INJECTIVITY INDEX
150.0
120.0
90.0
60.0
30.0
0.0
EFFECTIVE INJECT. INDEX PERCENT
TIME ON INJECTION
LEGEND: WELLID
AVERAGE
08-04-81-22

FIGURE 33

E.M.R. WELLS PERFORMANCE-AREA II

EFFECTIVE INJECTIVITY INDEX AS PERCENT OF PEAK AVERAGE EFFECTIVE INJECTIVITY INDEX

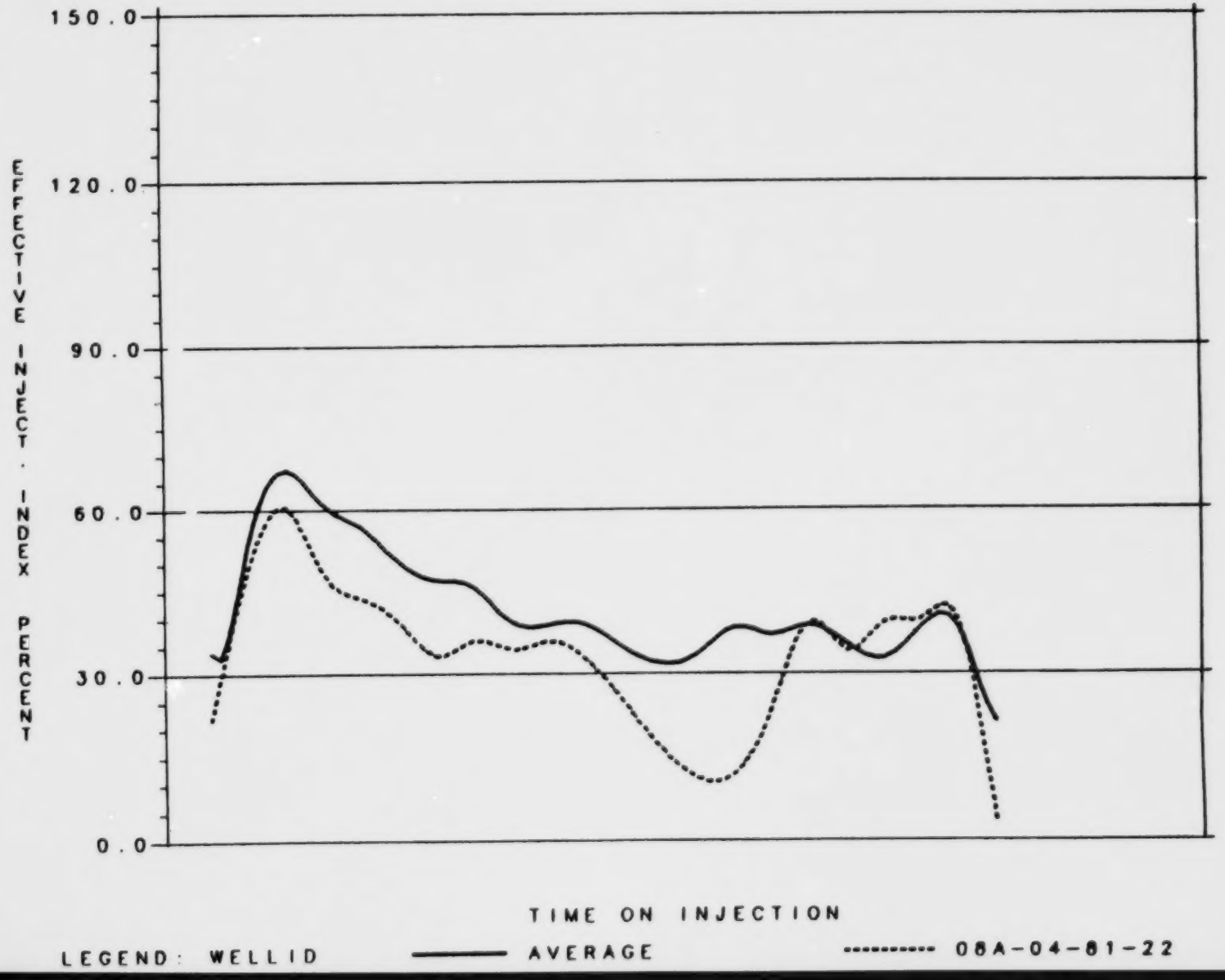


FIGURE 34

E.M.R. WELLS PERFORMANCE-AREA II

EFFECTIVE INJECTIVITY INDEX AS PERCENT OF PEAK AVERAGE EFFECTIVE INJECTIVITY INDEX

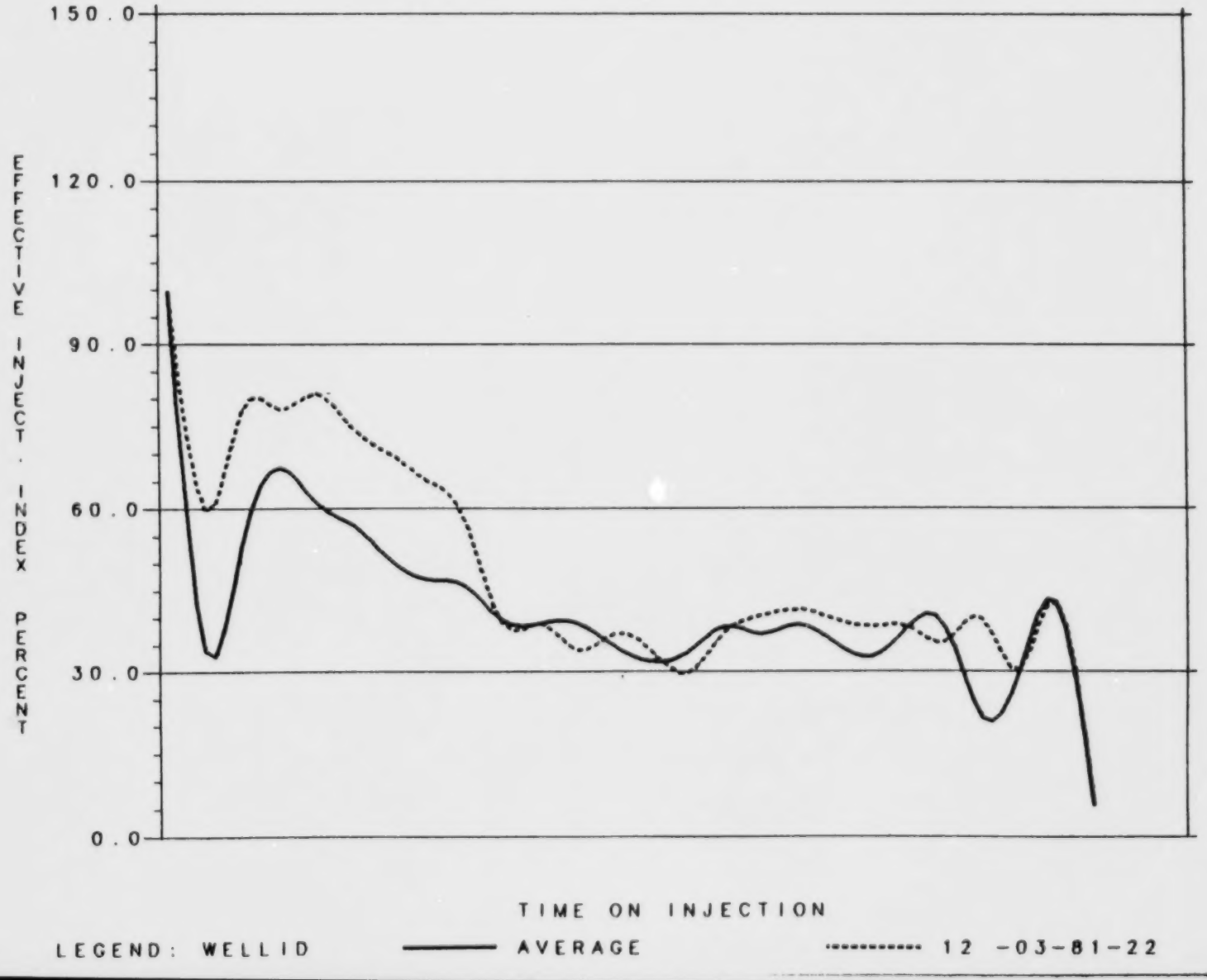


FIGURE 35

FIGURE 36

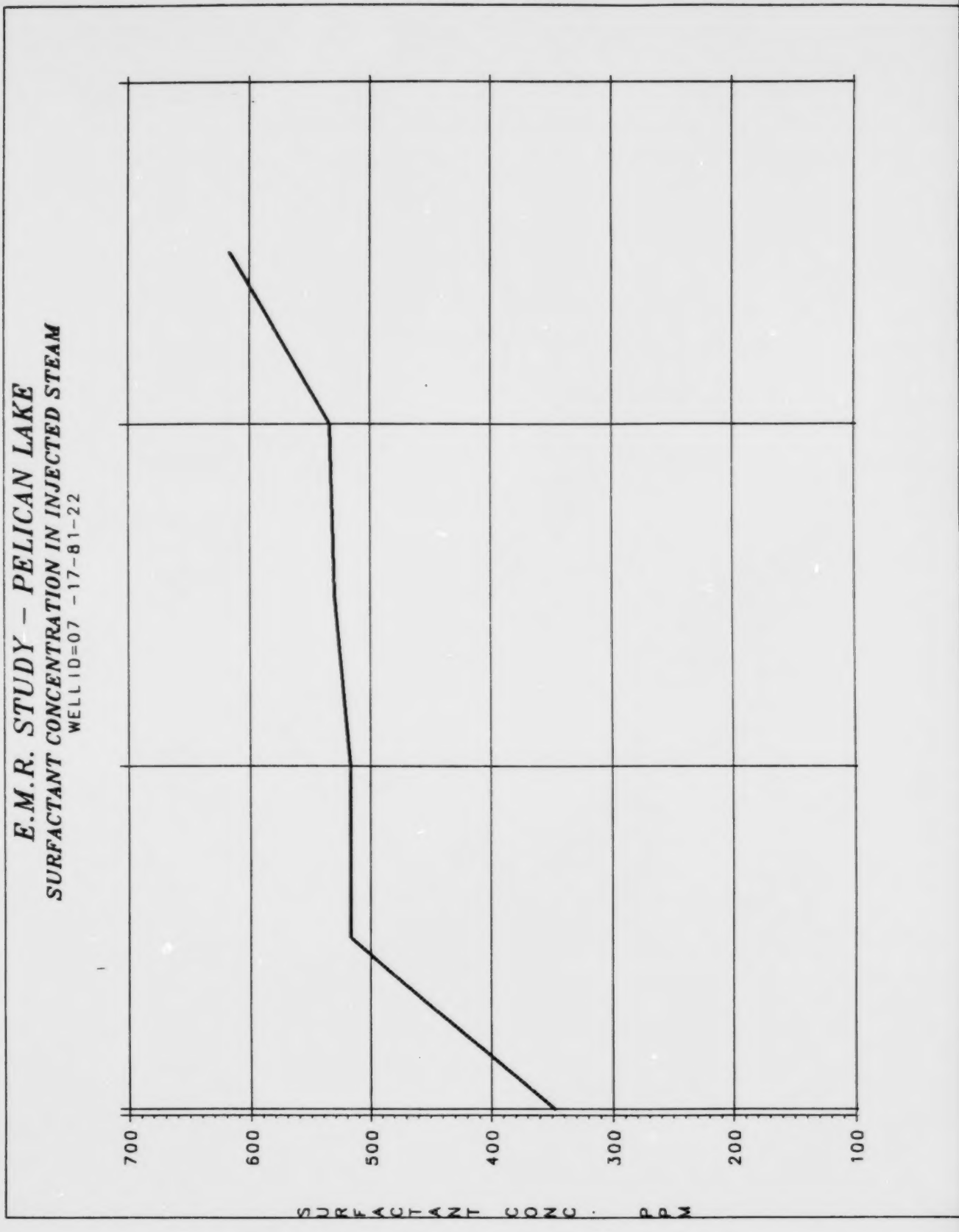

E.M.R. STUDY – PELICAN LAKE
SURFACTANT CONCENTRATION IN INJECTED STEAM
WELL ID=07 -17-81-22
700
600
500
400
300
200
100
SURFACTANT CONC. PPM

FIGURE 37

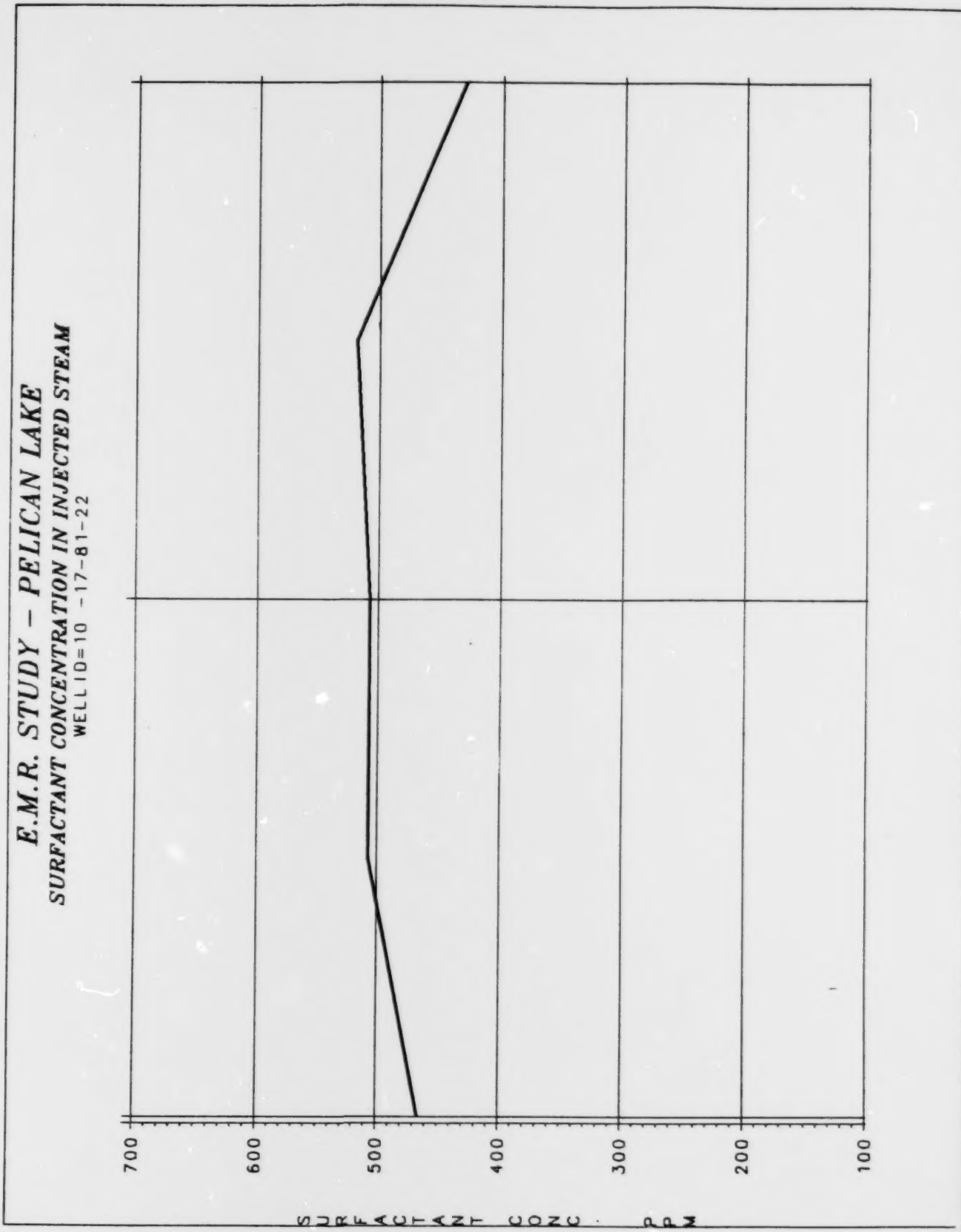
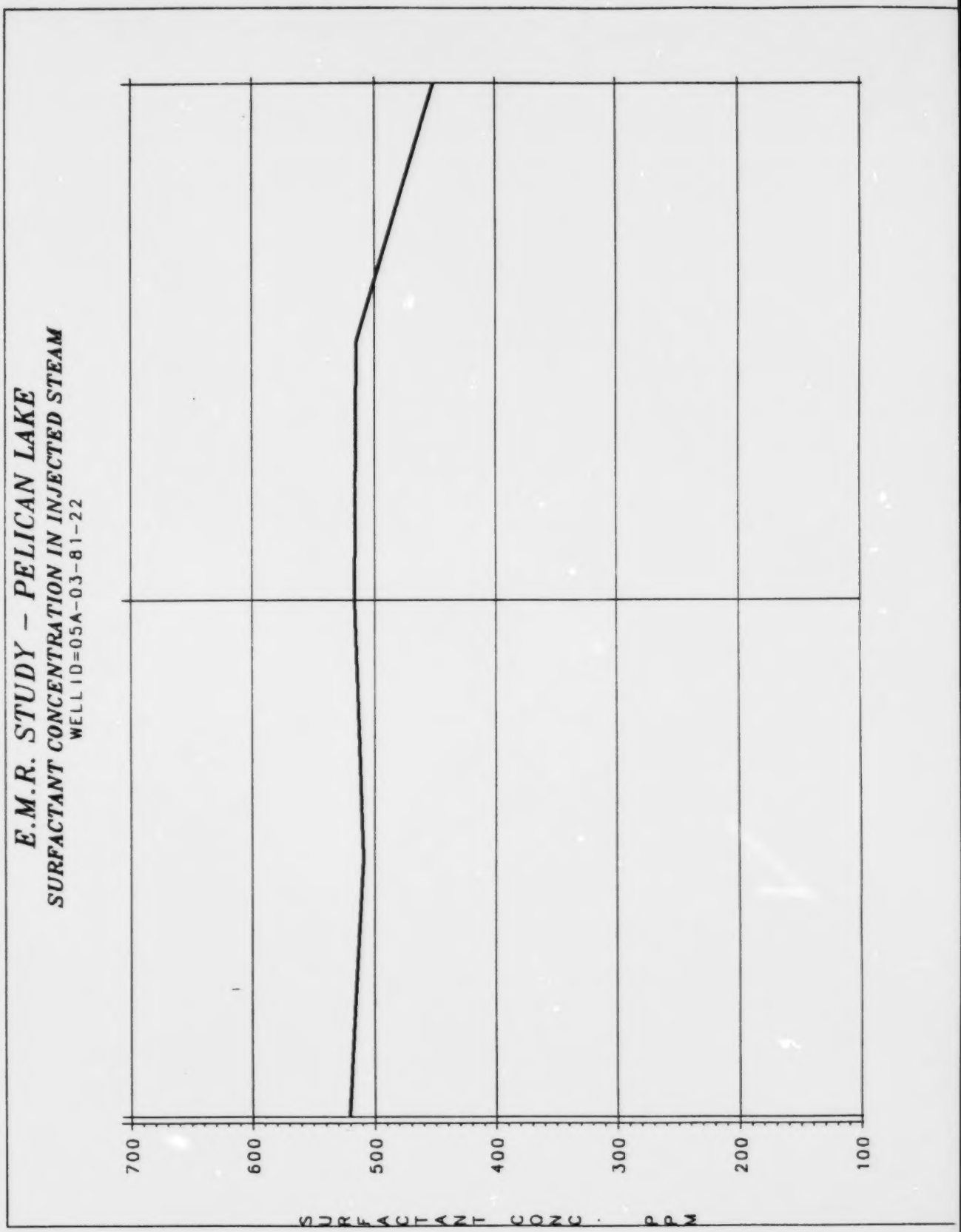

E.M.R. STUDY – PELICAN LAKE
SURFACTANT CONCENTRATION IN INJECTED STEAM
WELL ID=10 -17-81-22
700
600
500
400
300
200
100
SURFACTANT CONC. PPM

FIGURE 38


E.M.R. STUDY – PELICAN LAKE
SURFACTANT CONCENTRATION IN INJECTED STEAM
WELL ID=05A-03-81-22
700
600
500
400
300
200
100
SURFACTANT CONC. PPM

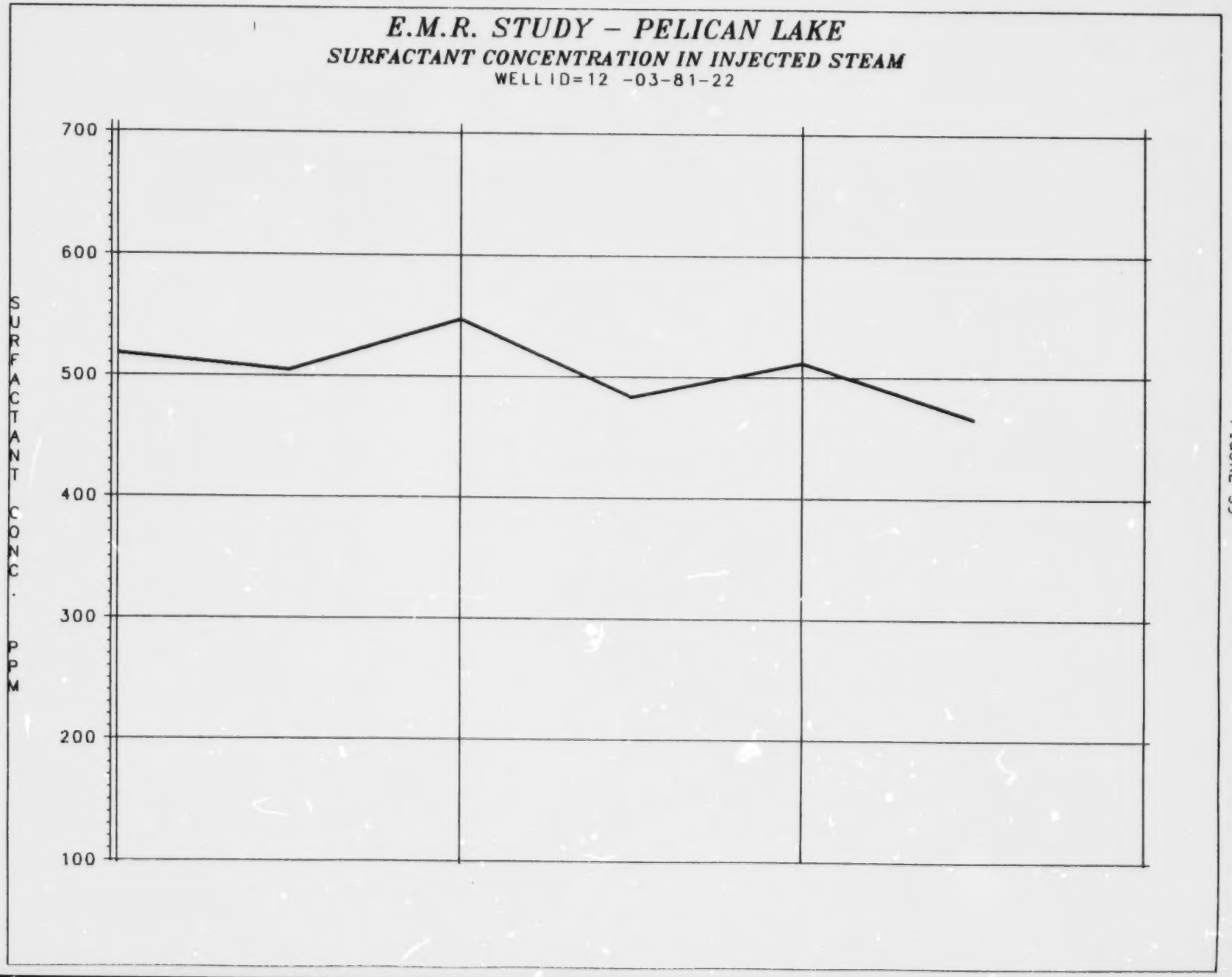

E.M.R. STUDY – PELICAN LAKE
SURFACTANT CONCENTRATION IN INJECTED STEAM
WELL ID=12 -03-81-22
SURFACTANT CONC. PPM
700
600
500
400
300
200
100

FIGURE 39

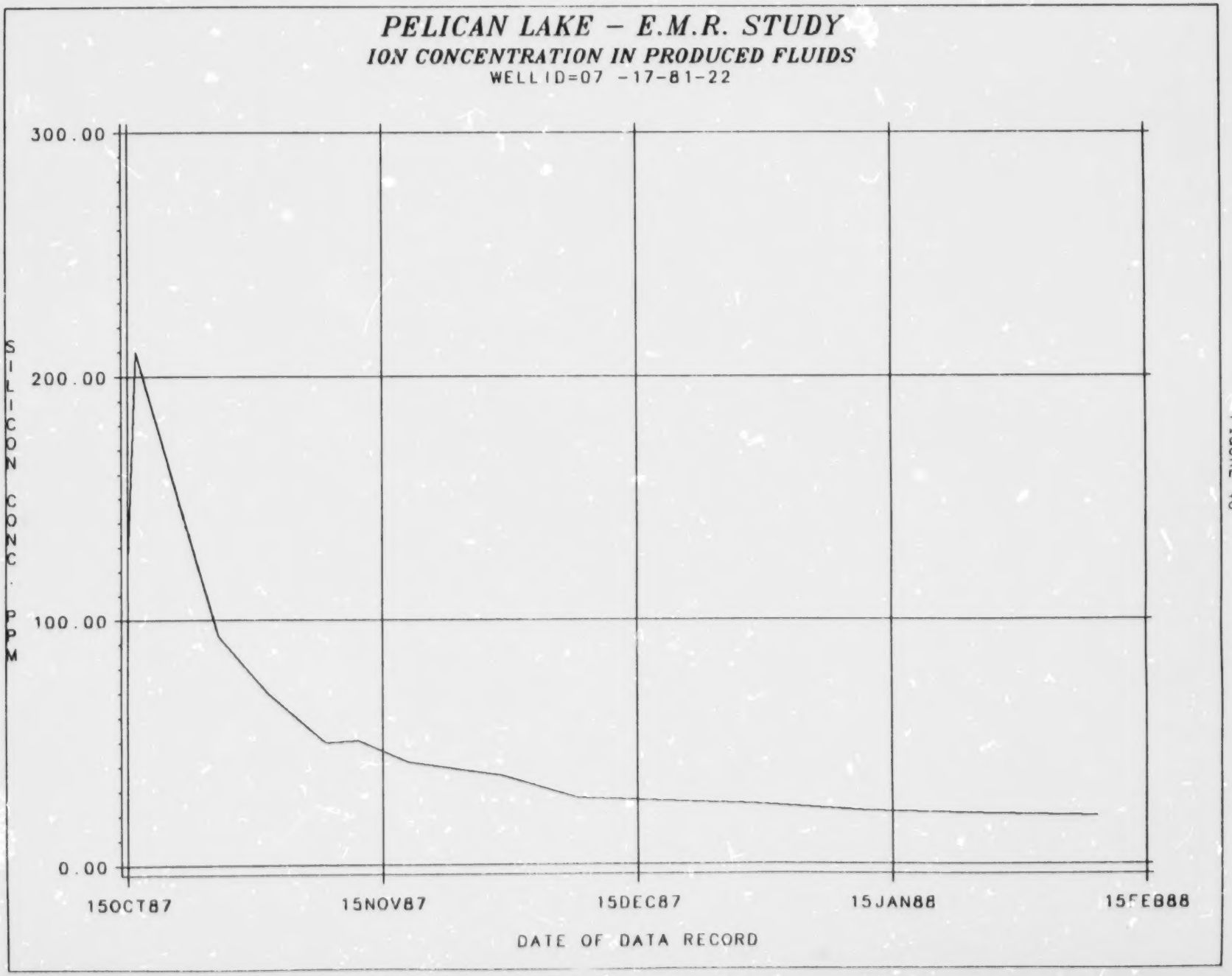
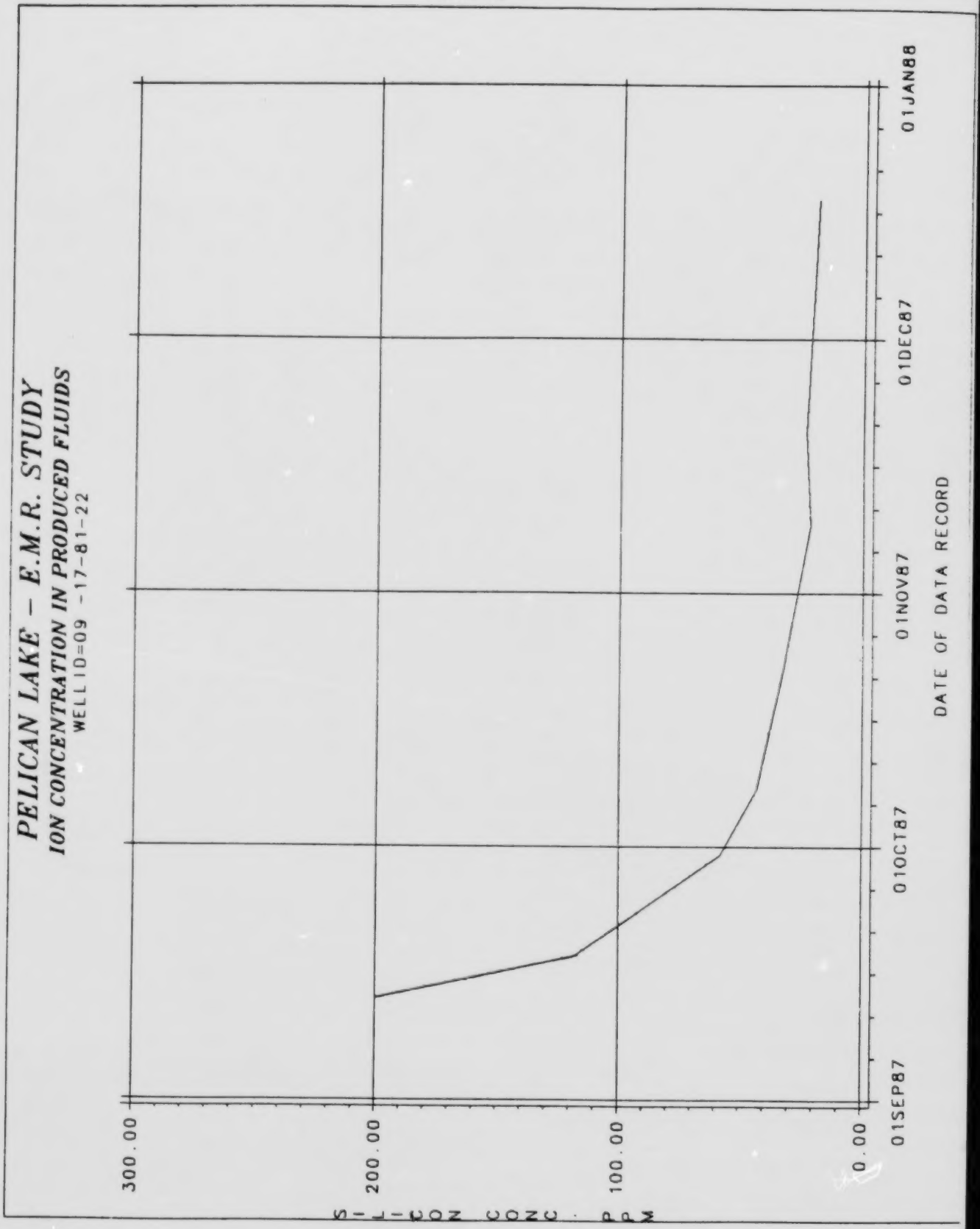

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=07 -17-81-22
300.00
200.00
100.00
0.00
SI-CON CONC. PPM
15OCT87
15NOV87
15DEC87
15JAN88
15FEB88
DATE OF DATA RECORD

FIGURE 40

FIGURE 41


PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=09 -17-81-22
S-1-CON CONC. PPM
300.00
200.00
100.00
0.00
01SEP87
01OCT87
01NOV87
01DEC87
01JAN88
DATE OF DATA RECORD

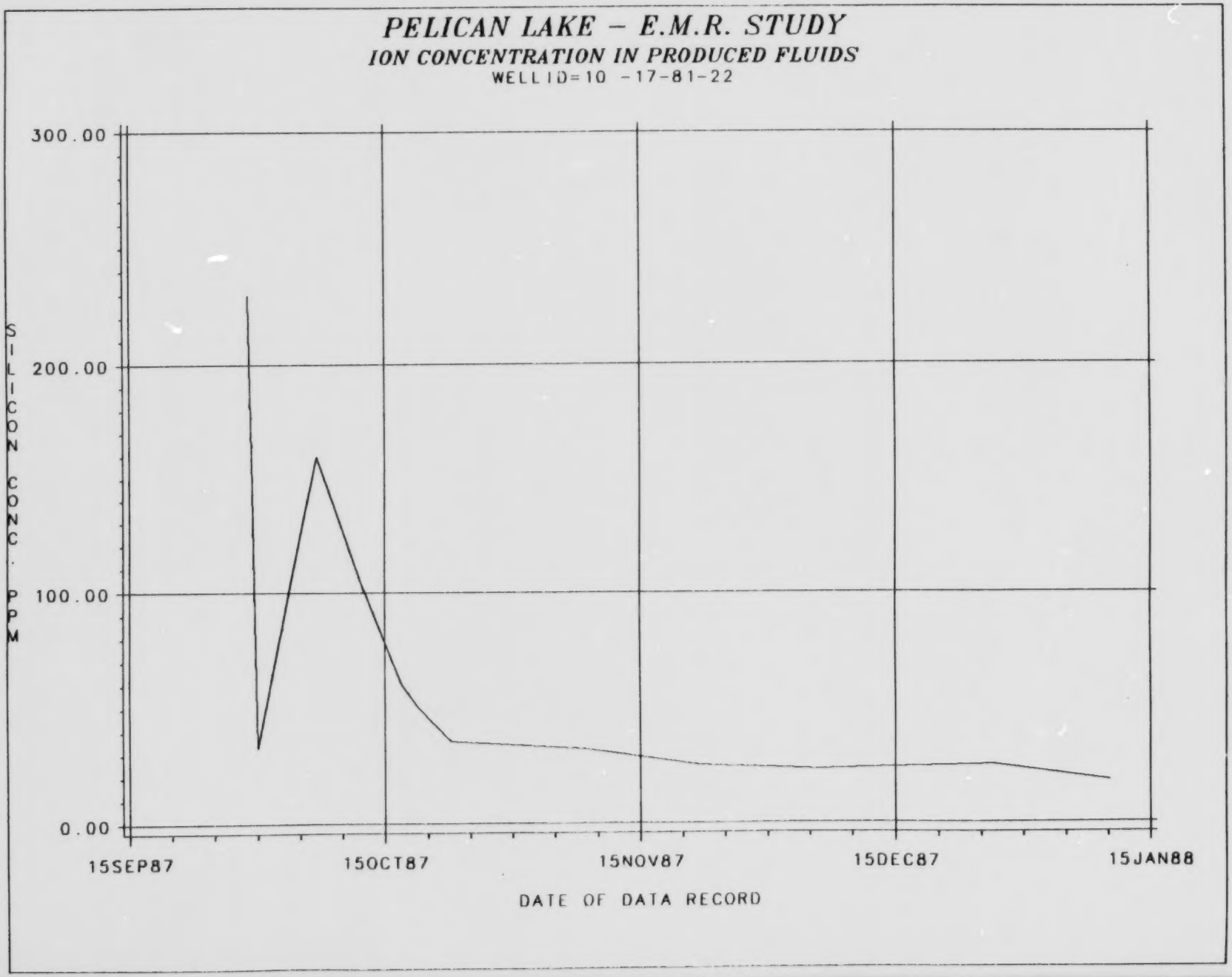

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=10 -17-81-22
300.00
200.00
100.00
0.00
SO4-SQZ CONC. PPM
15SEP87
15OCT87
15NOV87
15DEC87
15JAN88
DATE OF DATA RECORD

FIGURE 42

FIGURE 43

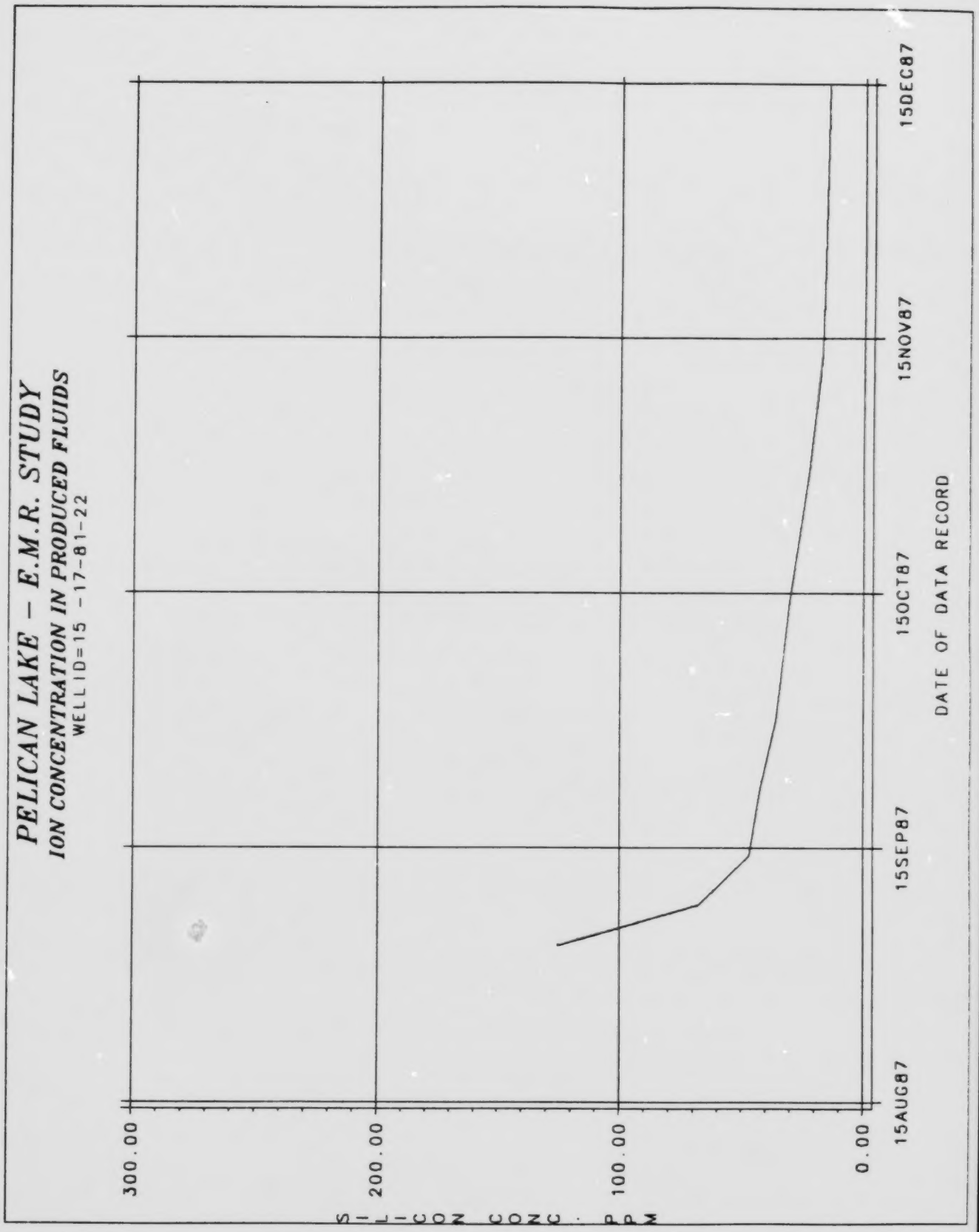
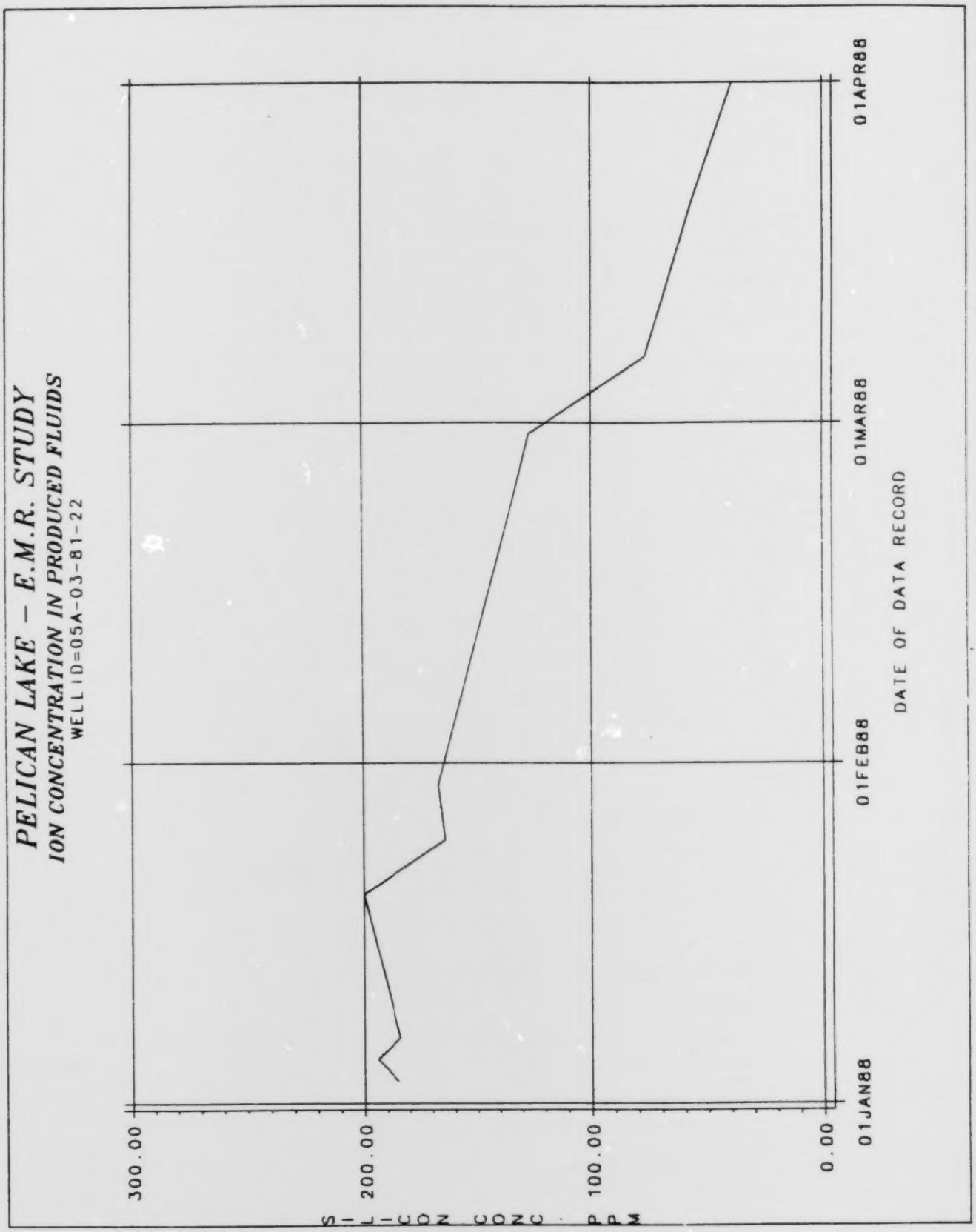

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELLID=15 -17-81-22
S-L-CON CONC. PPM
300.00
200.00
100.00
0.00
15AUG87
15SEP87
15OCT87
15NOV87
15DEC87
DATE OF DATA RECORD

FIGURE 44


PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELLID=05A-03-81-22
300.00
200.00
100.00
0.00
SI-L-CON CONC. PPM
01JAN88
01FEB88
01MAR88
01APR88
DATE OF DATA RECORD

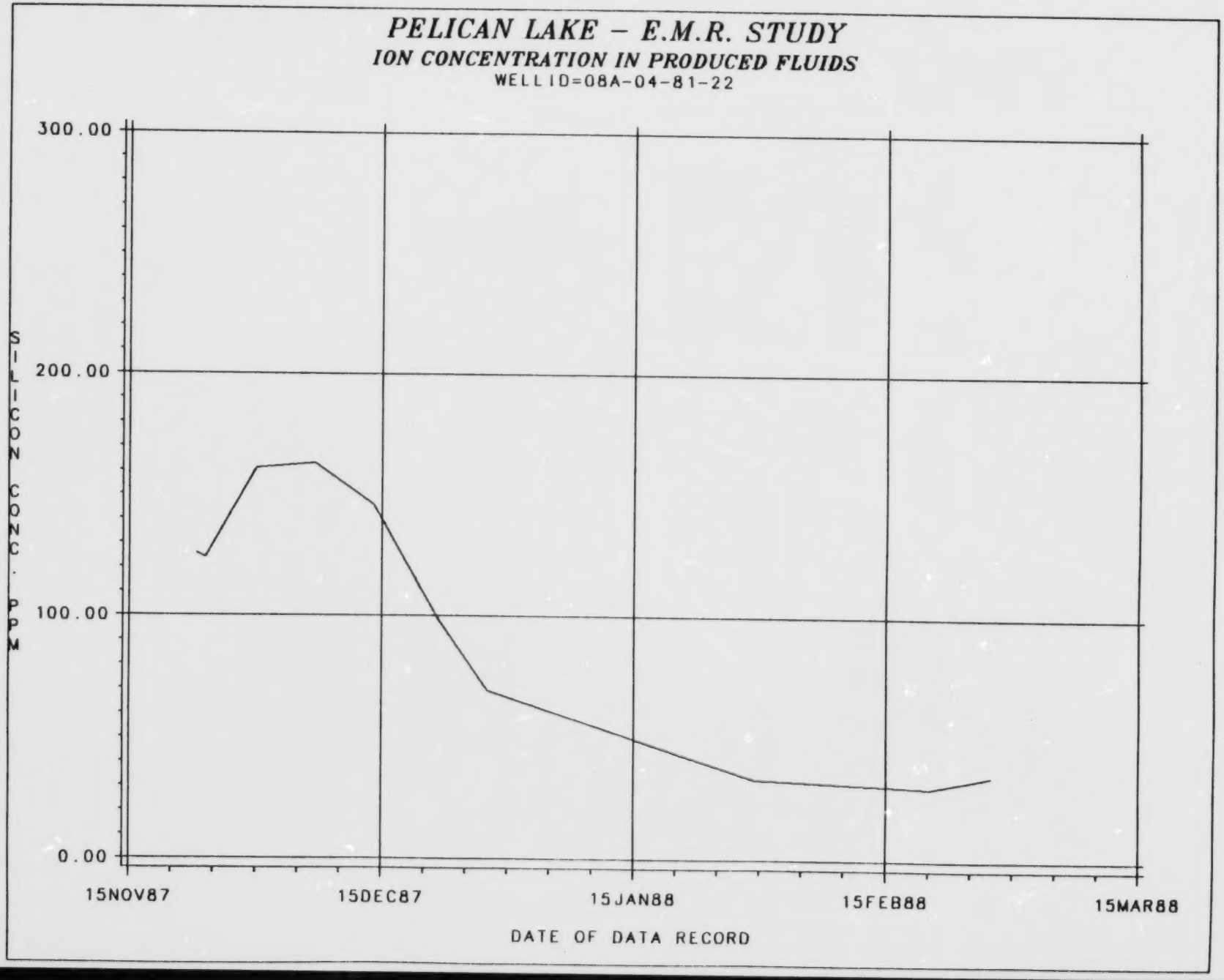

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=08A-04-81-22
300.00
200.00
100.00
0.00
SILICON CONC. PPM
15NOV87
15DEC87
15JAN88
15FEB88
15MAR88
DATE OF DATA RECORD

FIGURE 45

FIGURE 46

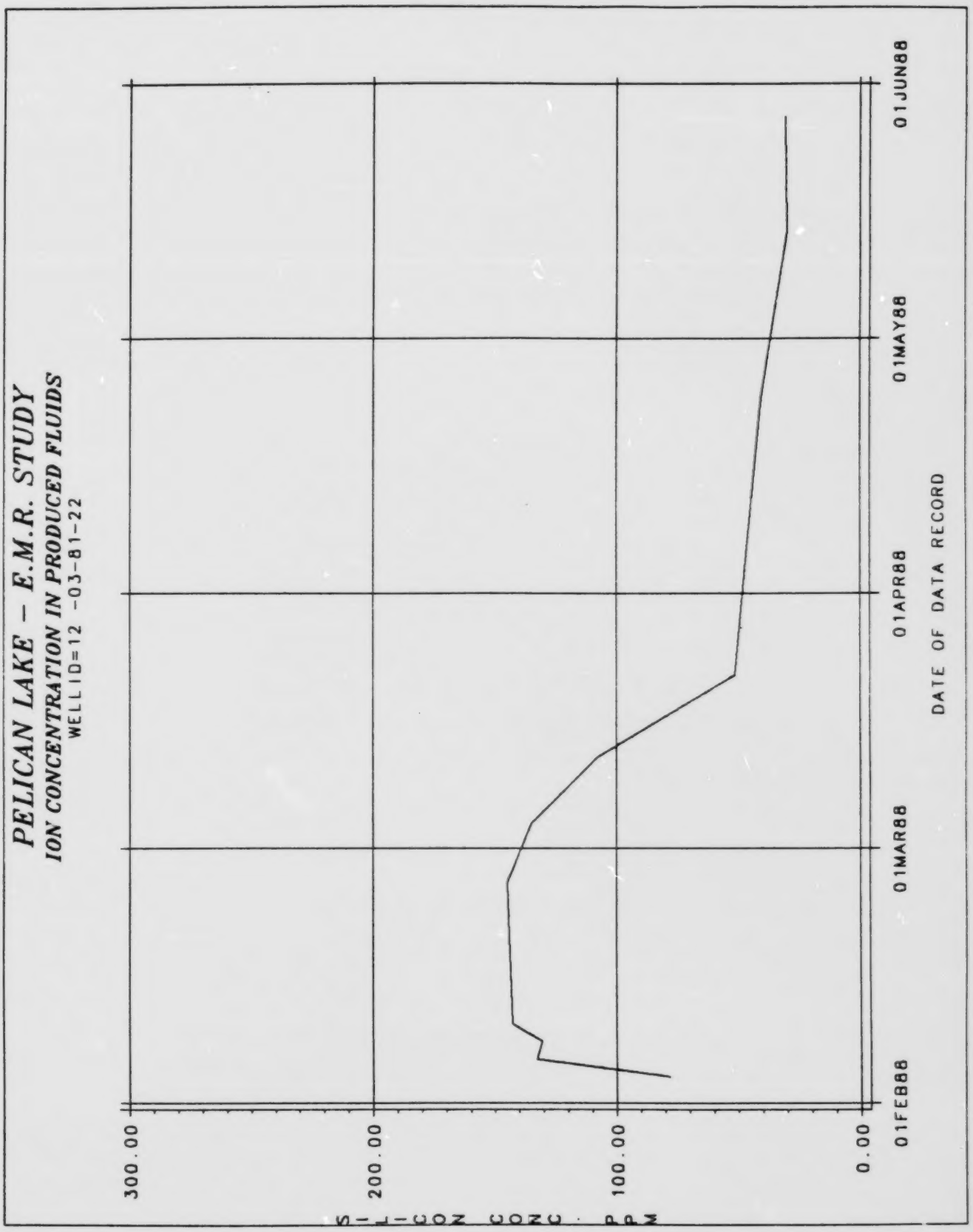
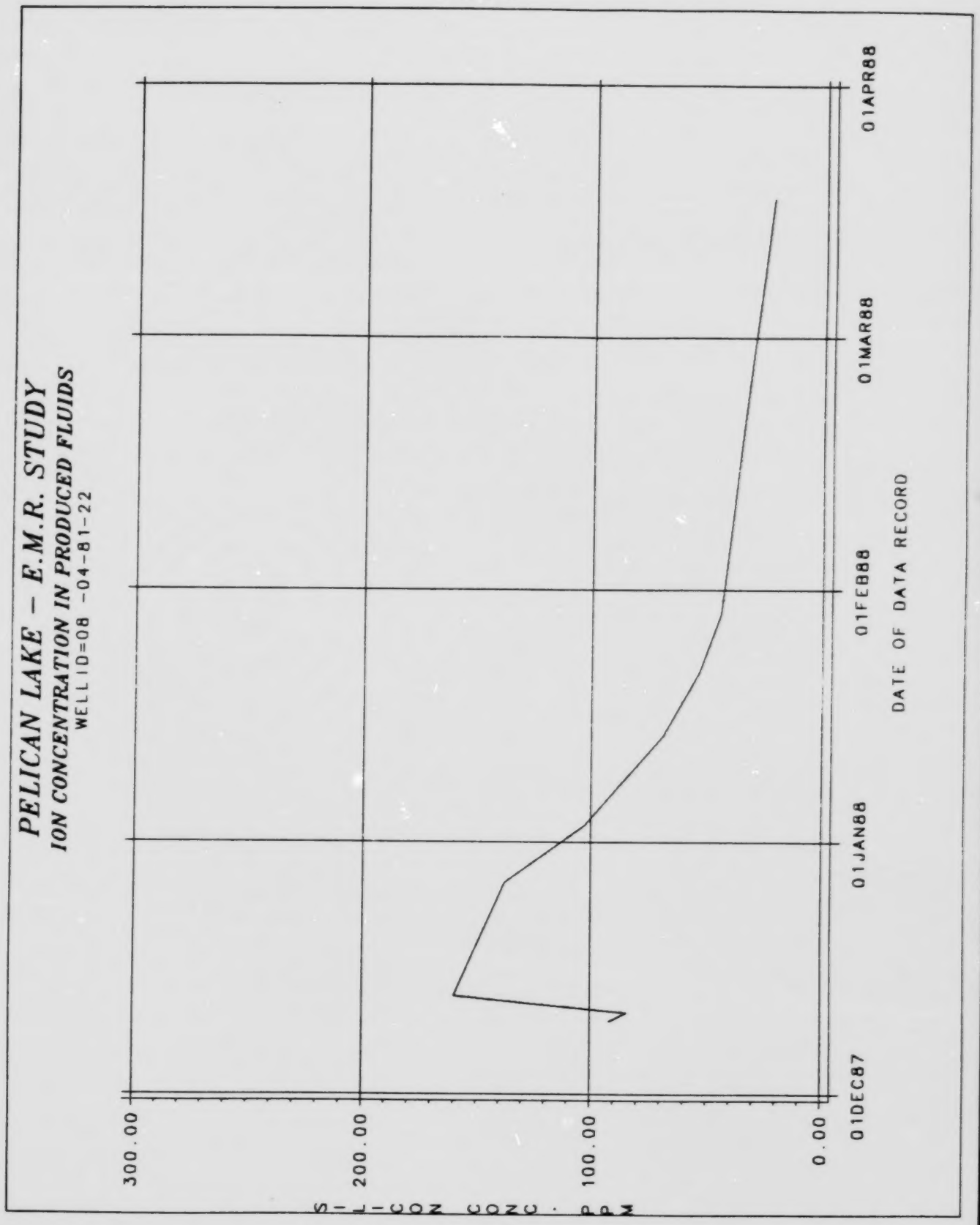

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELLID=12 -03-81-22
S-I-CON CONC. PPM
300.00
200.00
100.00
0.00
01FEB88
01MAR88
01APR88
01MAY88
01JUN88
DATE OF DATA RECORD

FIGURE 47


PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELLID=08 -04-81-22
S-L-CO3 HCO3-T-S
CO3 · PPM
300.00
200.00
100.00
0.00
01DEC87
01JAN88
01FEB88
01MAR88
01APR88
DATE OF DATA RECORD

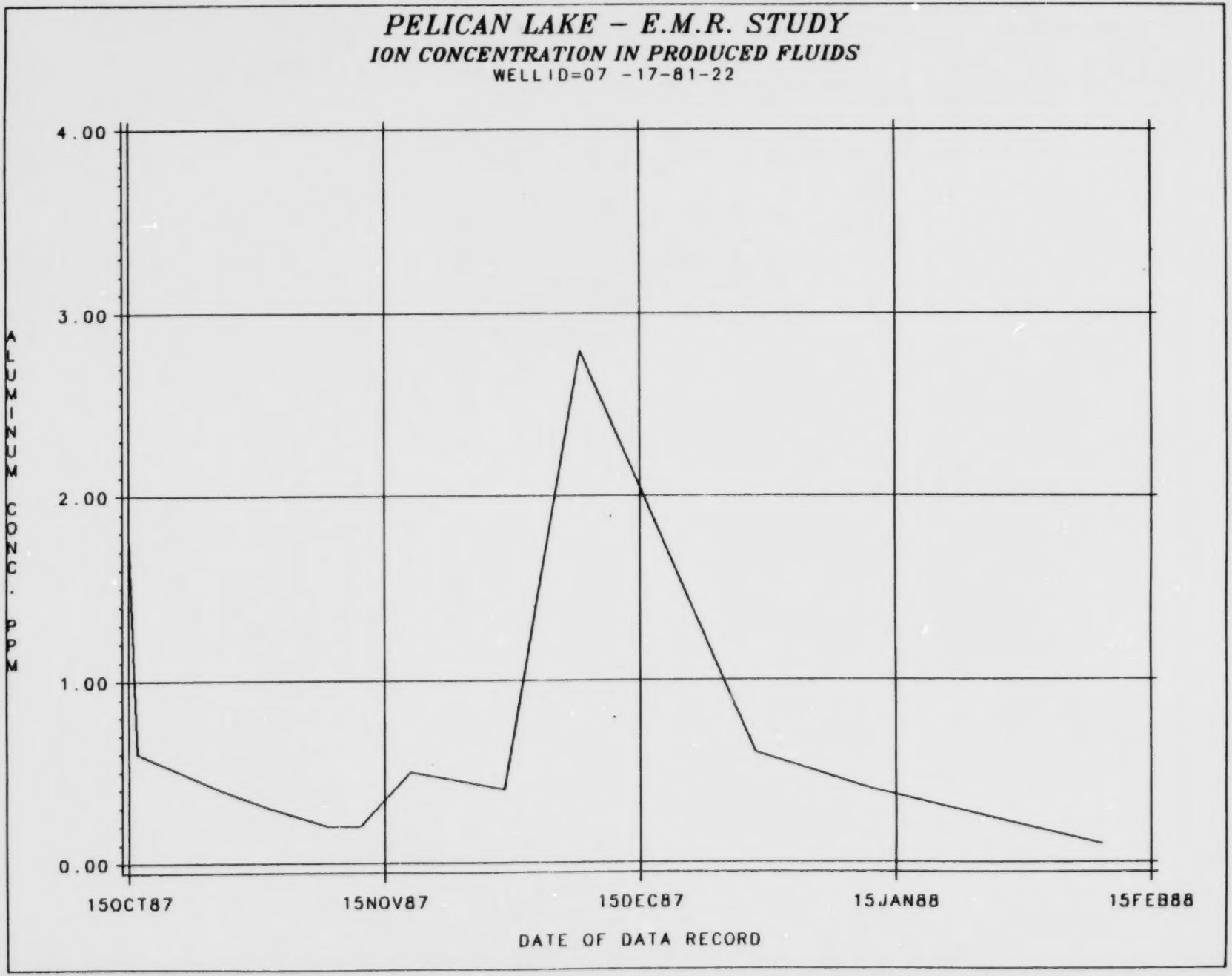

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=07 -17-81-22
4.00
3.00
2.00
1.00
0.00
15OCT87
15NOV87
15DEC87
15JAN88
15FEB88
DATE OF DATA RECORD

FIGURE 48

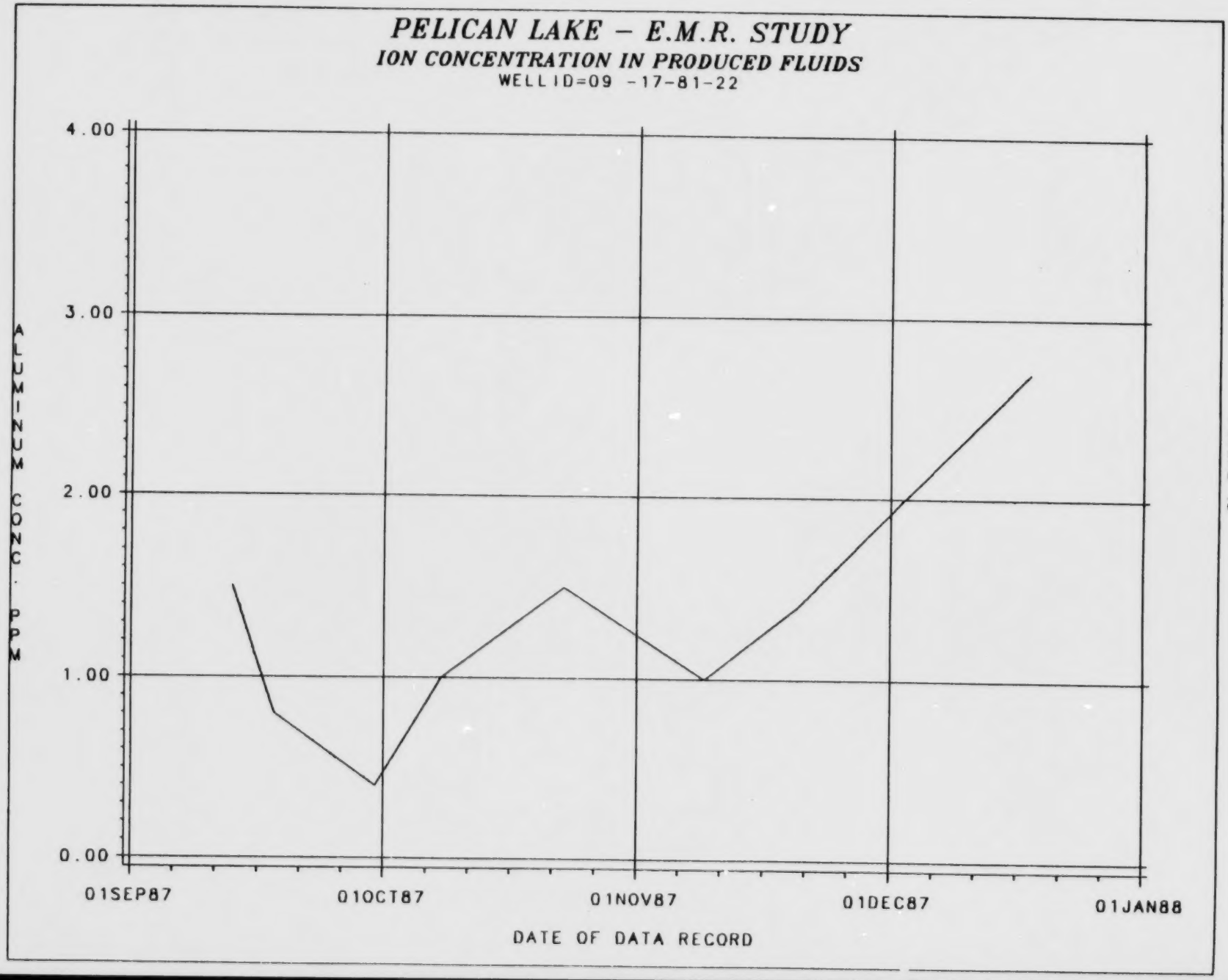

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=09 -17-81-22
4.00
3.00
2.00
1.00
0.00
01SEP87
01OCT87
01NOV87
01DEC87
01JAN88
DATE OF DATA RECORD

FIGURE 49

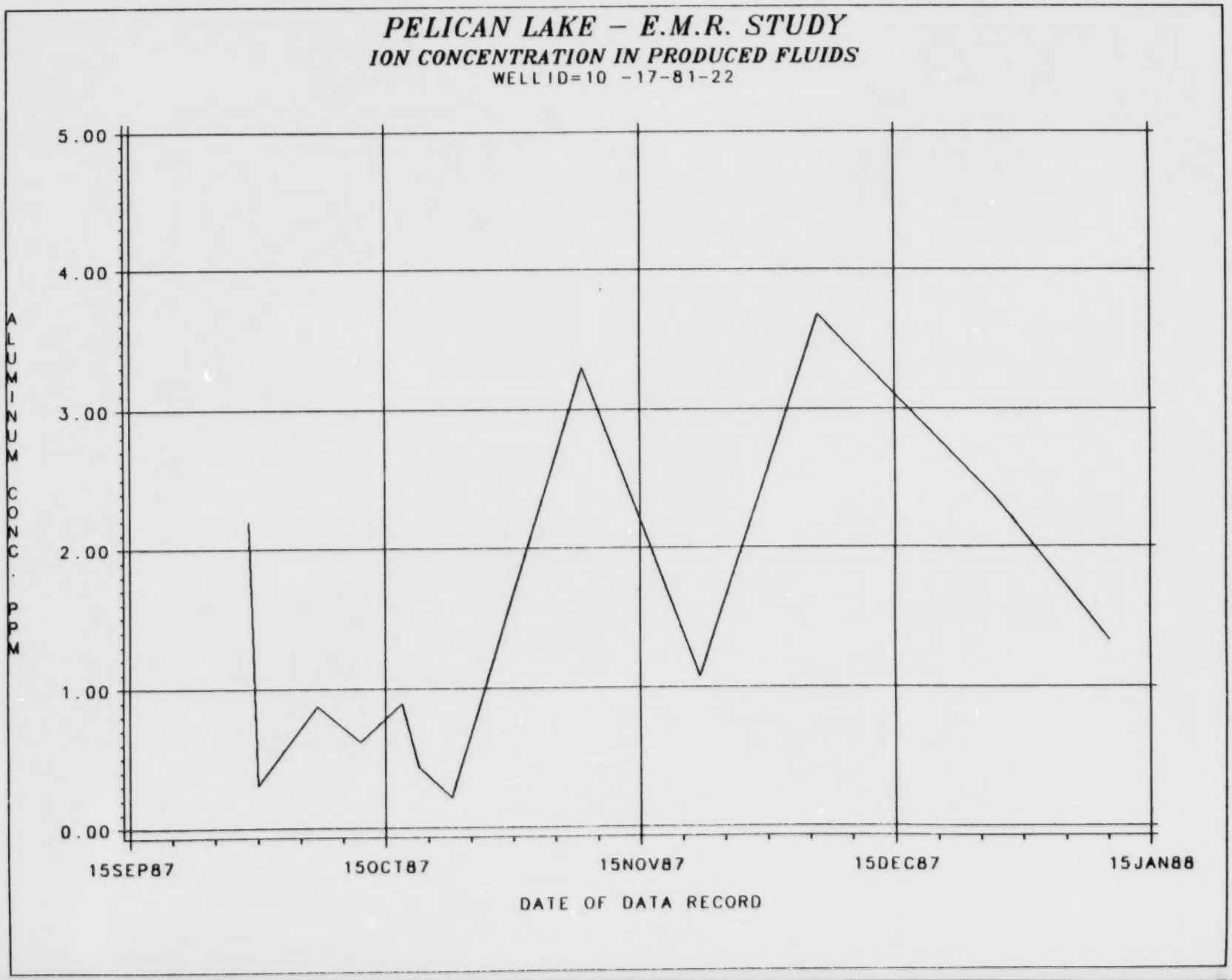

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=10 -17-81-22
5.00
4.00
3.00
2.00
1.00
0.00
ALUM-ZUM CONC. PPM
15SEP87
15OCT87
15NOV87
15DEC87
15JAN88
DATE OF DATA RECORD

FIGURE 50

FIGURE 51

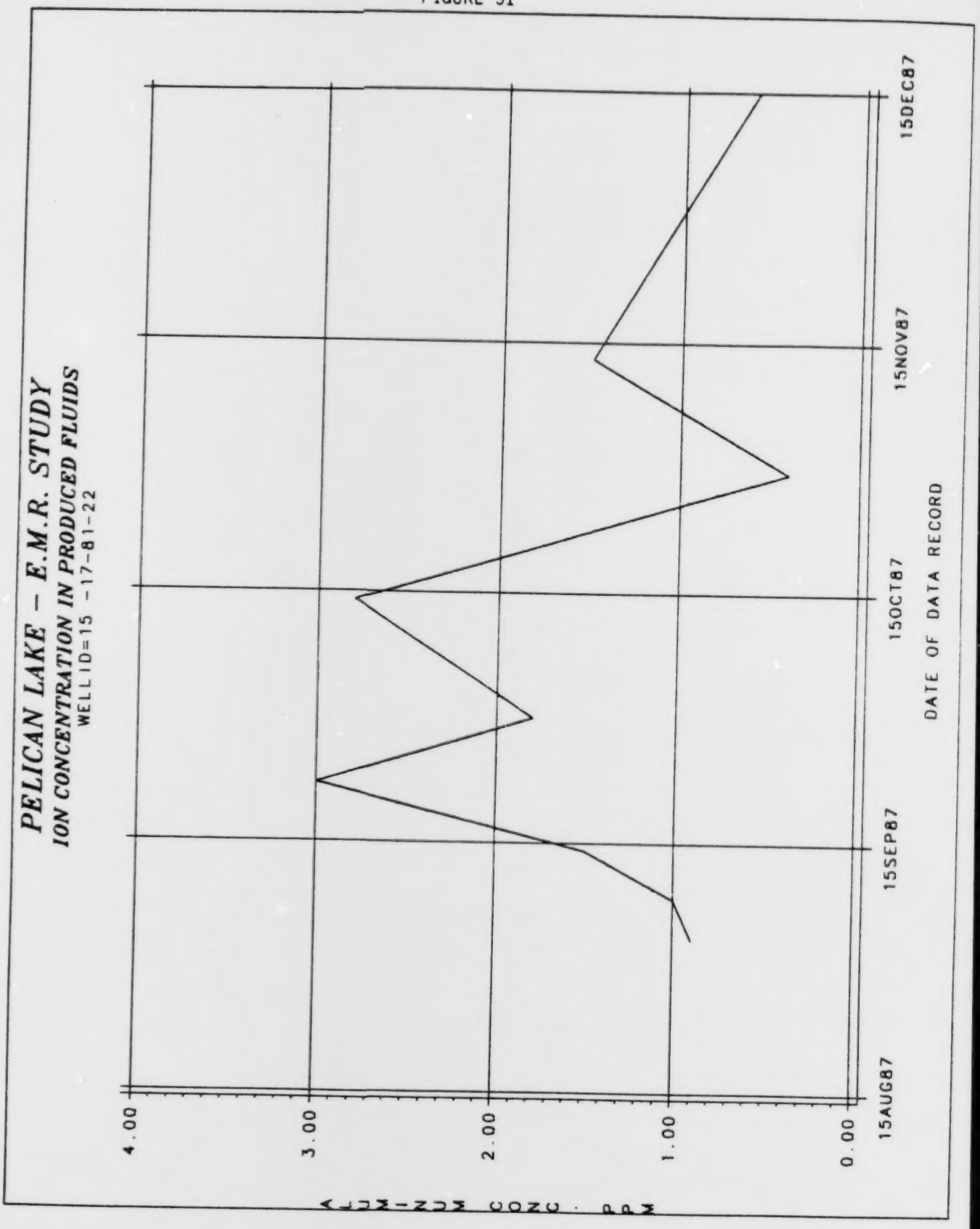

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELLID=15 -17-81-22
4.00
3.00
2.00
1.00
0.00
15AUG87
15SEP87
15OCT87
15NOV87
15DEC87
DATE OF DATA RECORD

FIGURE 52

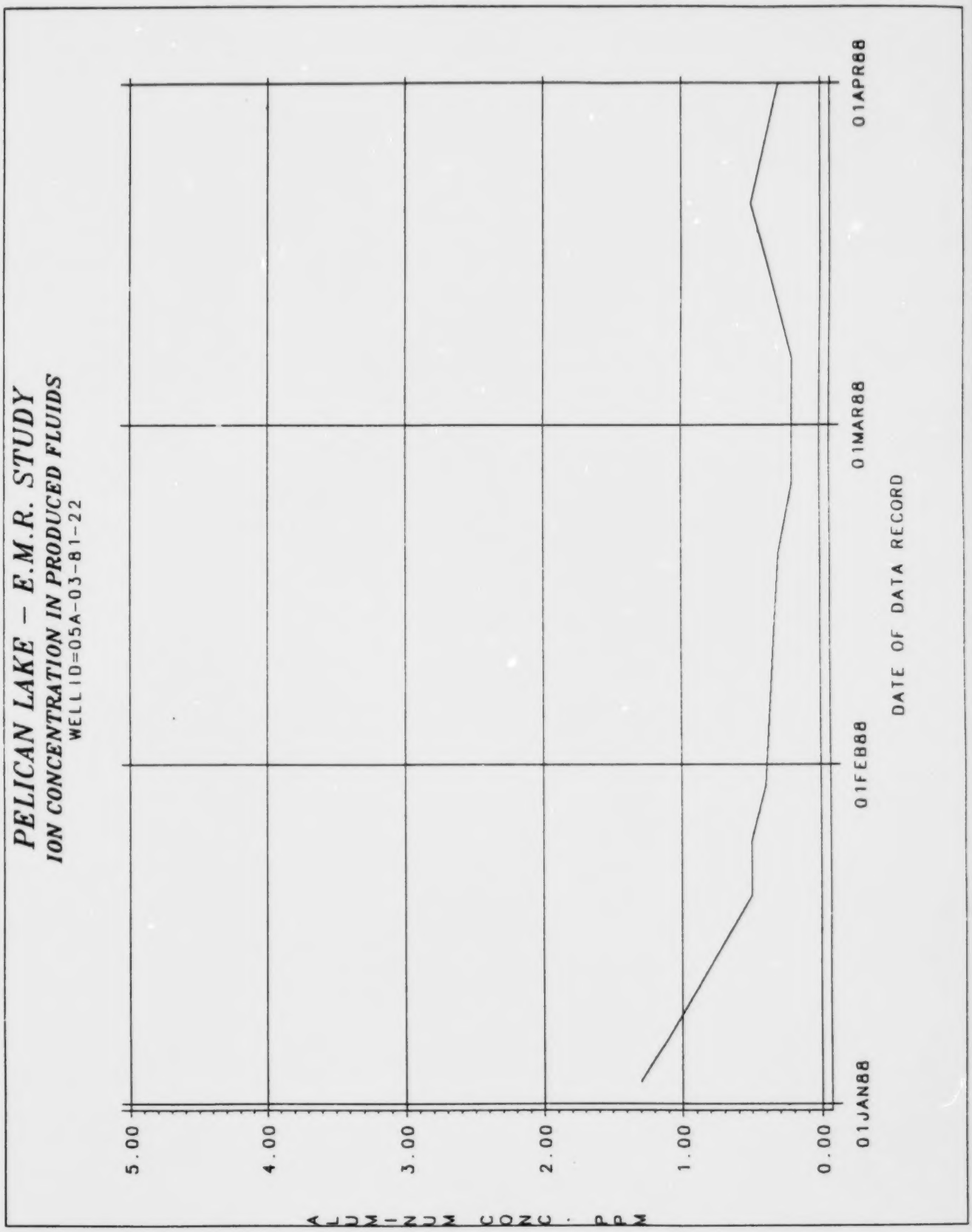
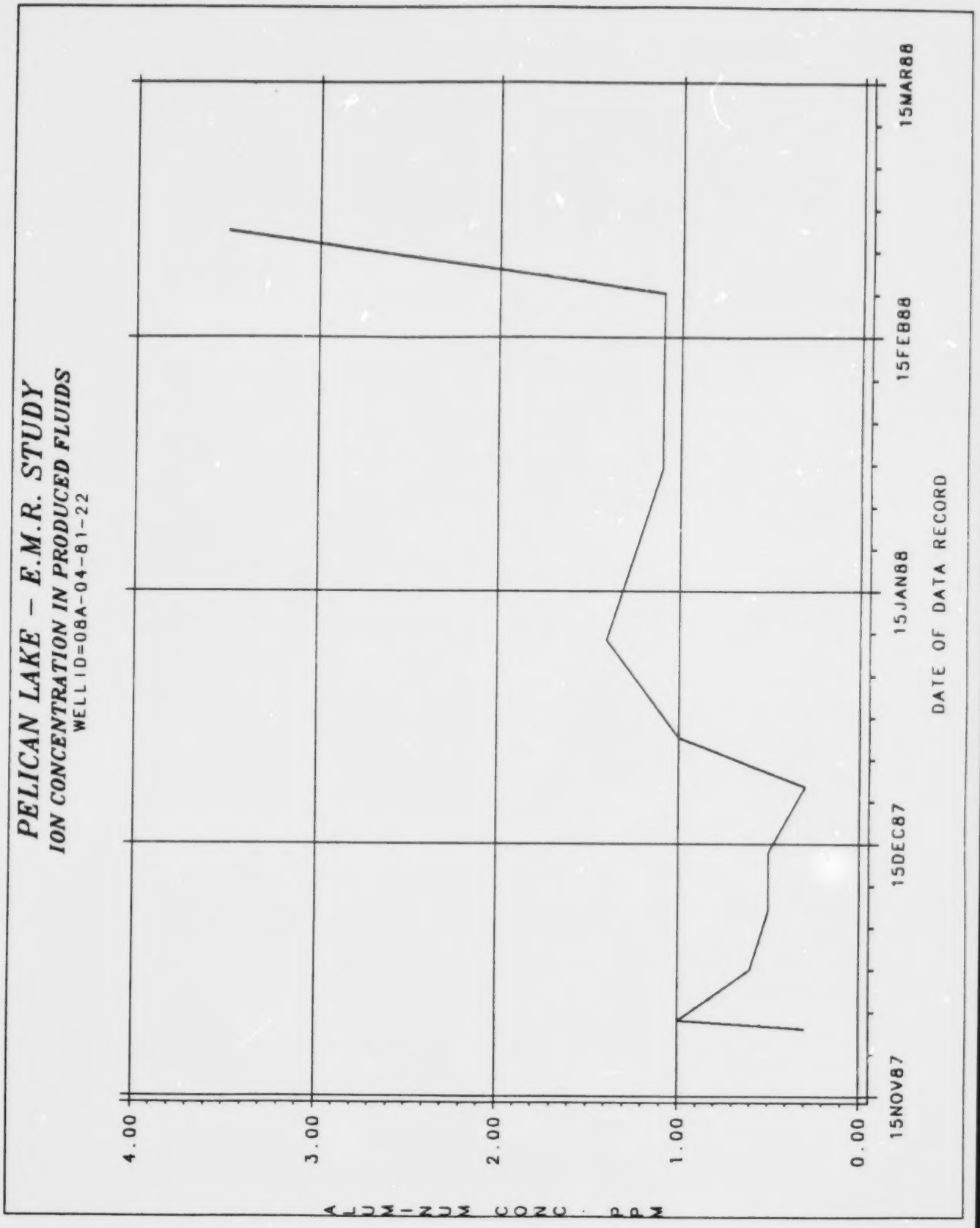

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=05A-03-81-22
ALUM-NUM CONC. PPM
5.00
4.00
3.00
2.00
1.00
0.00
01JAN88
01FEB88
01MAR88
01APR88
DATE OF DATA RECORD

FIGURE 53


PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=08A-04-81-22
4.00
3.00
2.00
1.00
0.00
15NOV87
15DEC87
15JAN88
15FEB88
15MAR88
DATE OF DATA RECORD

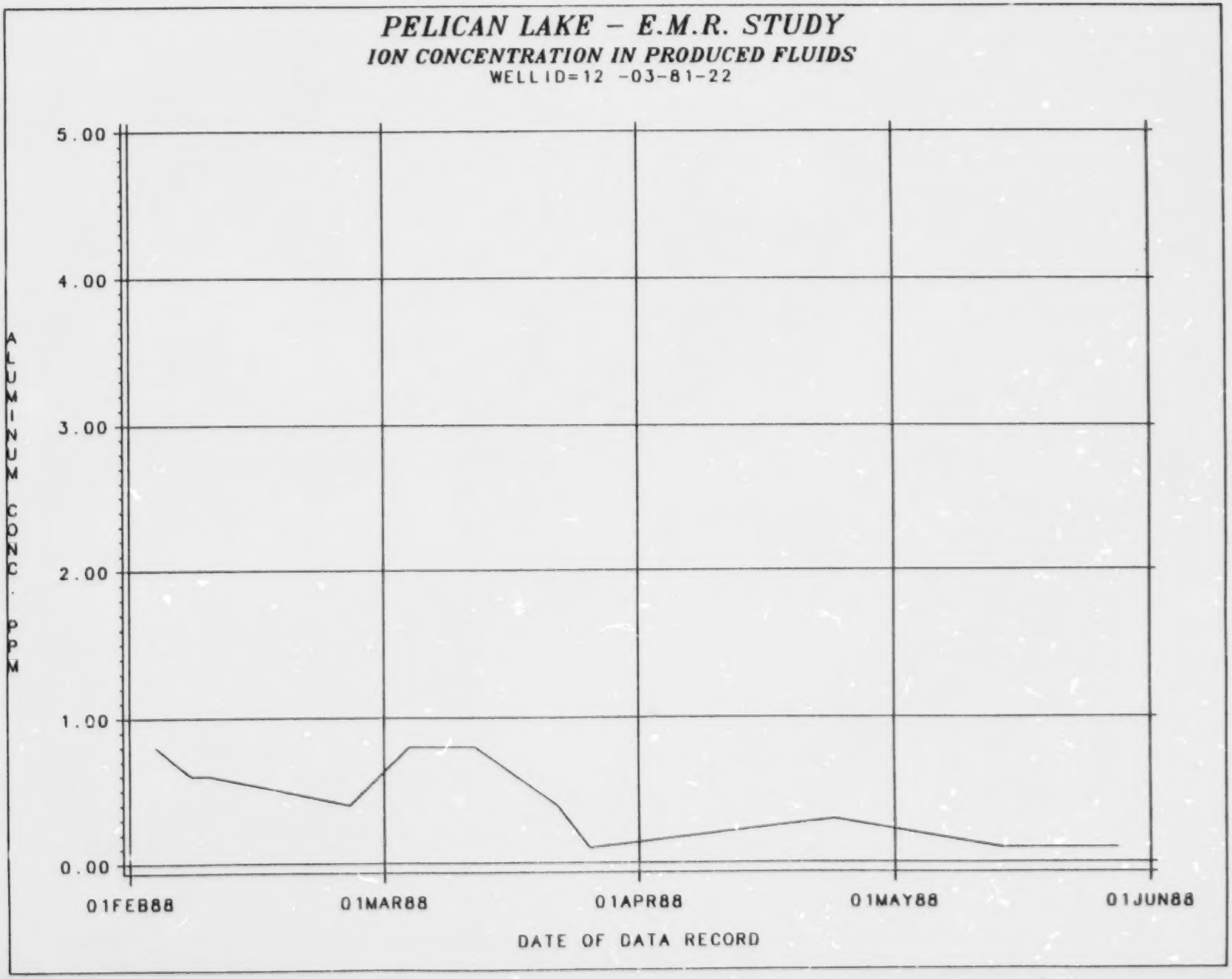

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=12 -03-81-22
5.00
4.00
3.00
2.00
1.00
0.00
01FEB88
01MAR88
01APR88
01MAY88
01JUN88
DATE OF DATA RECORD

FIGURE 54

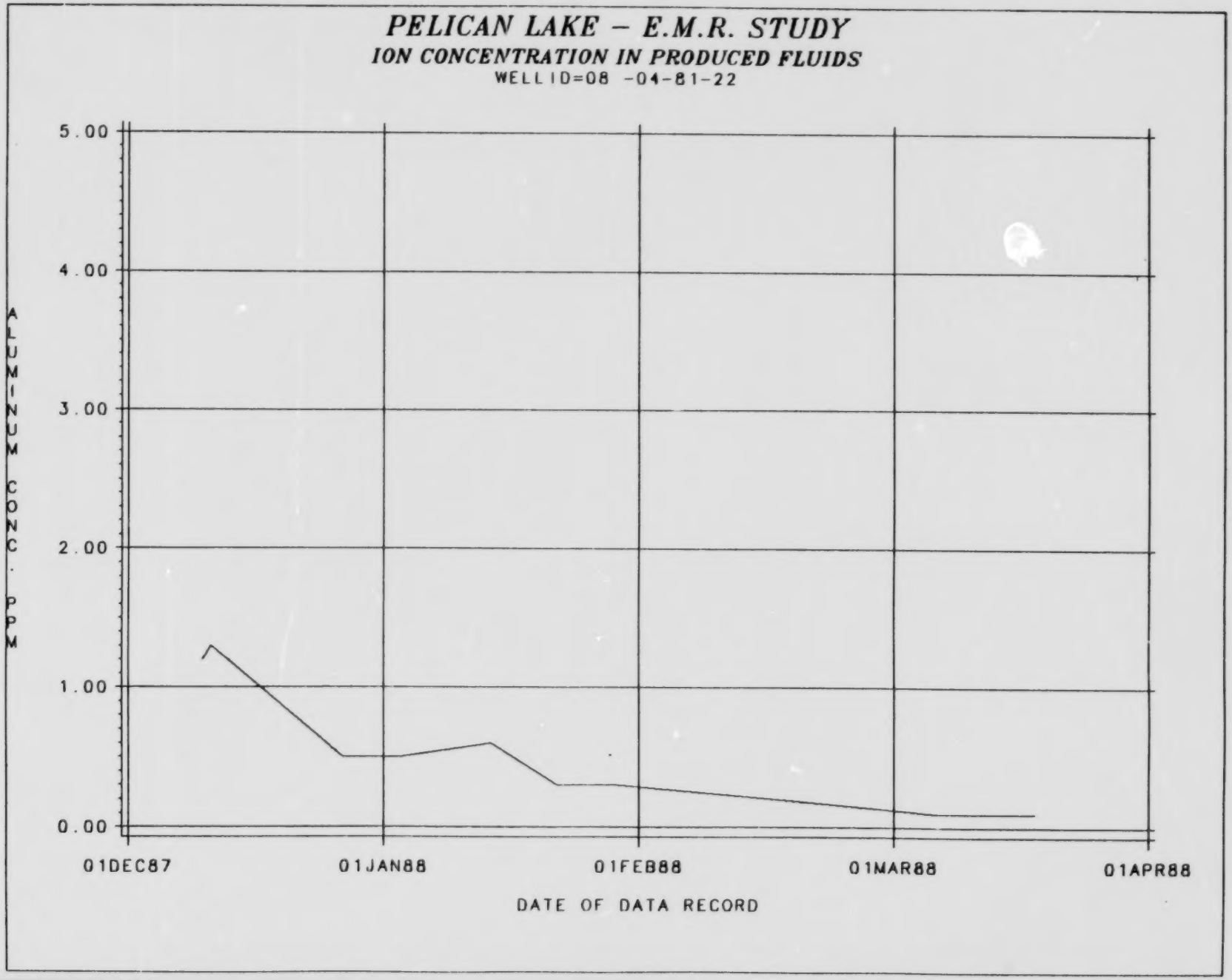

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=08 -04-81-22
5.00
4.00
3.00
2.00
1.00
0.00
ALUM-NUM CONC. PPM
01DEC87
01JAN88
01FEB88
01MAR88
01APR88
DATE OF DATA RECORD

FIGURE 55

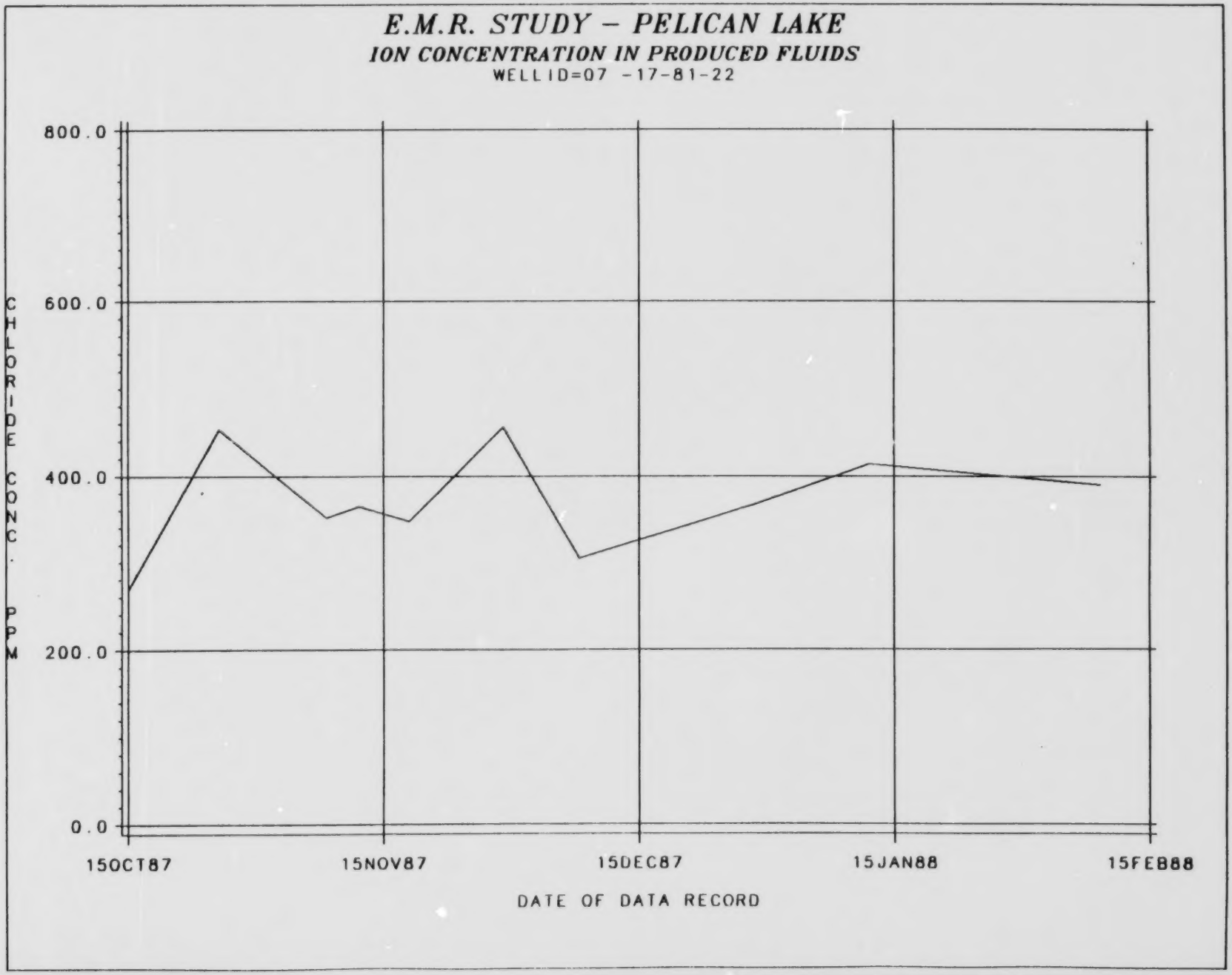
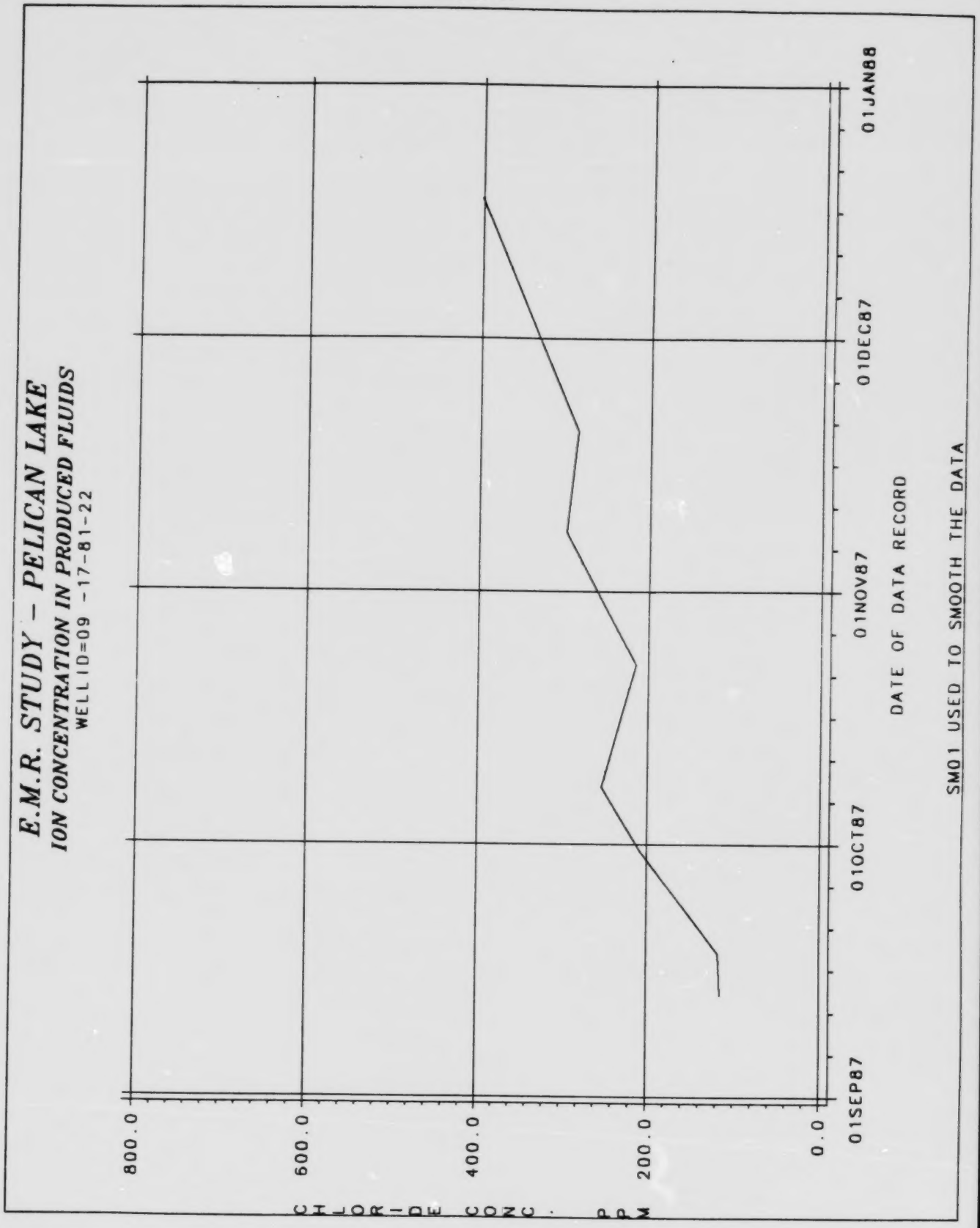

E.M.R. STUDY – PELICAN LAKE
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=07 -17-81-22
800.0
600.0
400.0
200.0
0.0
CHLORIDE CONC. PPM
15OCT87
15NOV87
15DEC87
15JAN88
15FEB88
DATE OF DATA RECORD

FIGURE 56

FIGURE 57


E.M.R. STUDY – PELICAN LAKE
ION CONCENTRATION IN PRODUCED FLUIDS
WELLID=09 -17-81-22
CHLORIDE CONC. PPM
800.0
600.0
400.0
200.0
0.0
01SEP87
01OCT87
01NOV87
01DEC87
01JAN88
DATE OF DATA RECORD
SM01 USED TO SMOOTH THE DATA

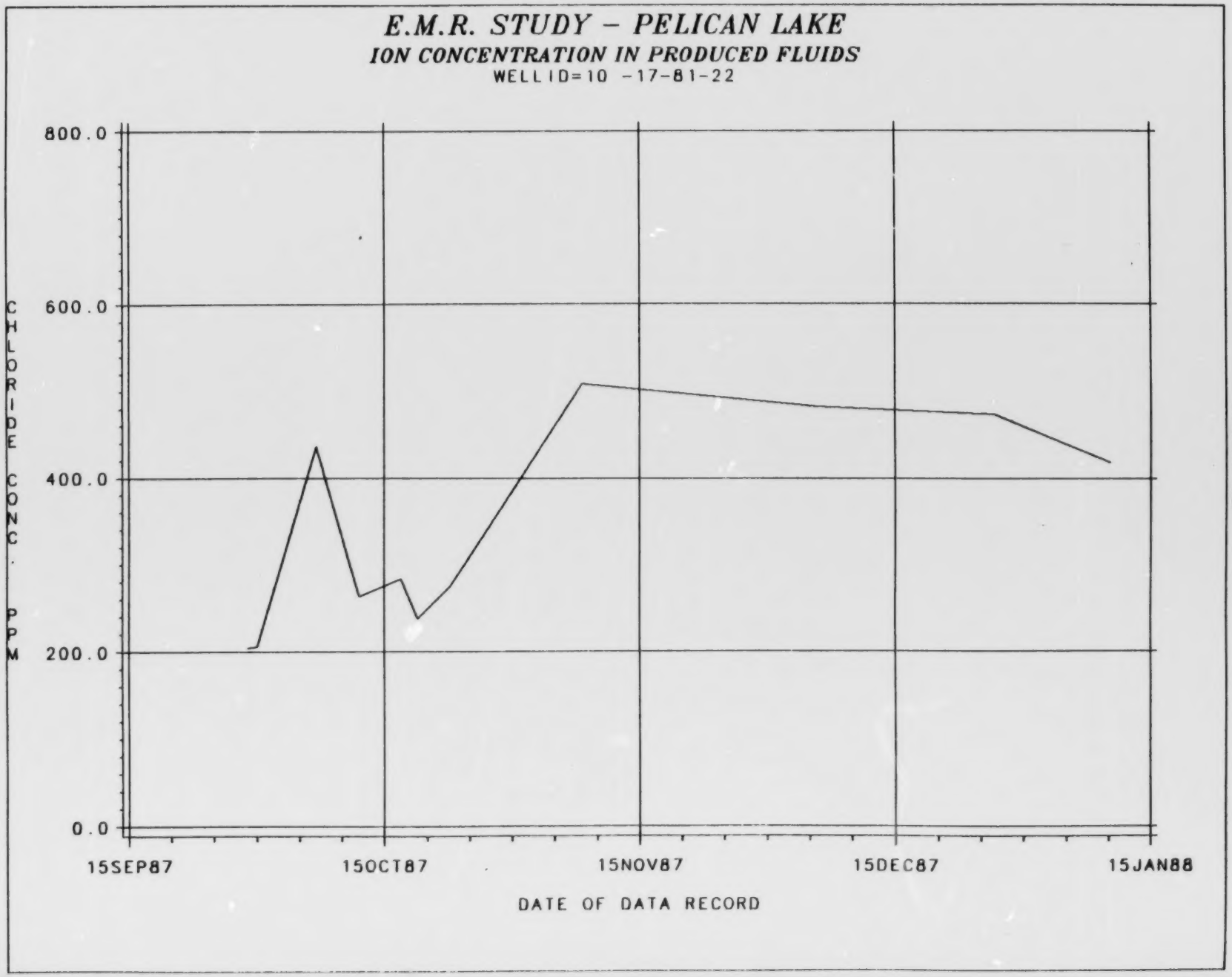
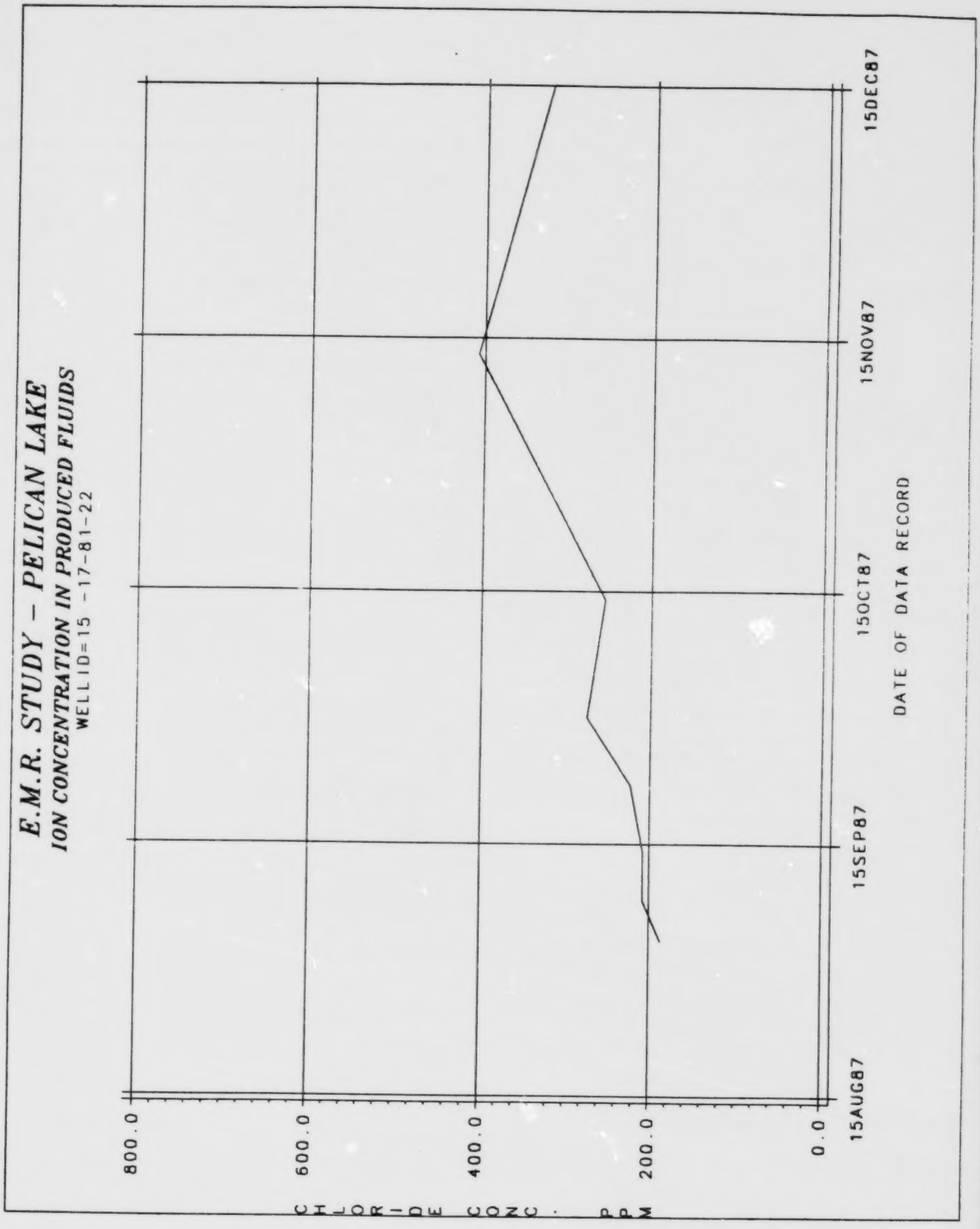

E.M.R. STUDY – PELICAN LAKE
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=10 -17-81-22
800.0
600.0
400.0
200.0
0.0
CHLORIDE CONC. PPM
15SEP87
15OCT87
15NOV87
15DEC87
15JAN88
DATE OF DATA RECORD

FIGURE 58

FIGURE 59


E.M.R. STUDY – PELICAN LAKE
ION CONCENTRATION IN PRODUCED FLUIDS
WELLID=15 -17-81-22
CHLORIDE CONC. PPM
800.0
600.0
400.0
200.0
0.0
15AUG87
15SEP87
15OCT87
15NOV87
15DEC87
DATE OF DATA RECORD

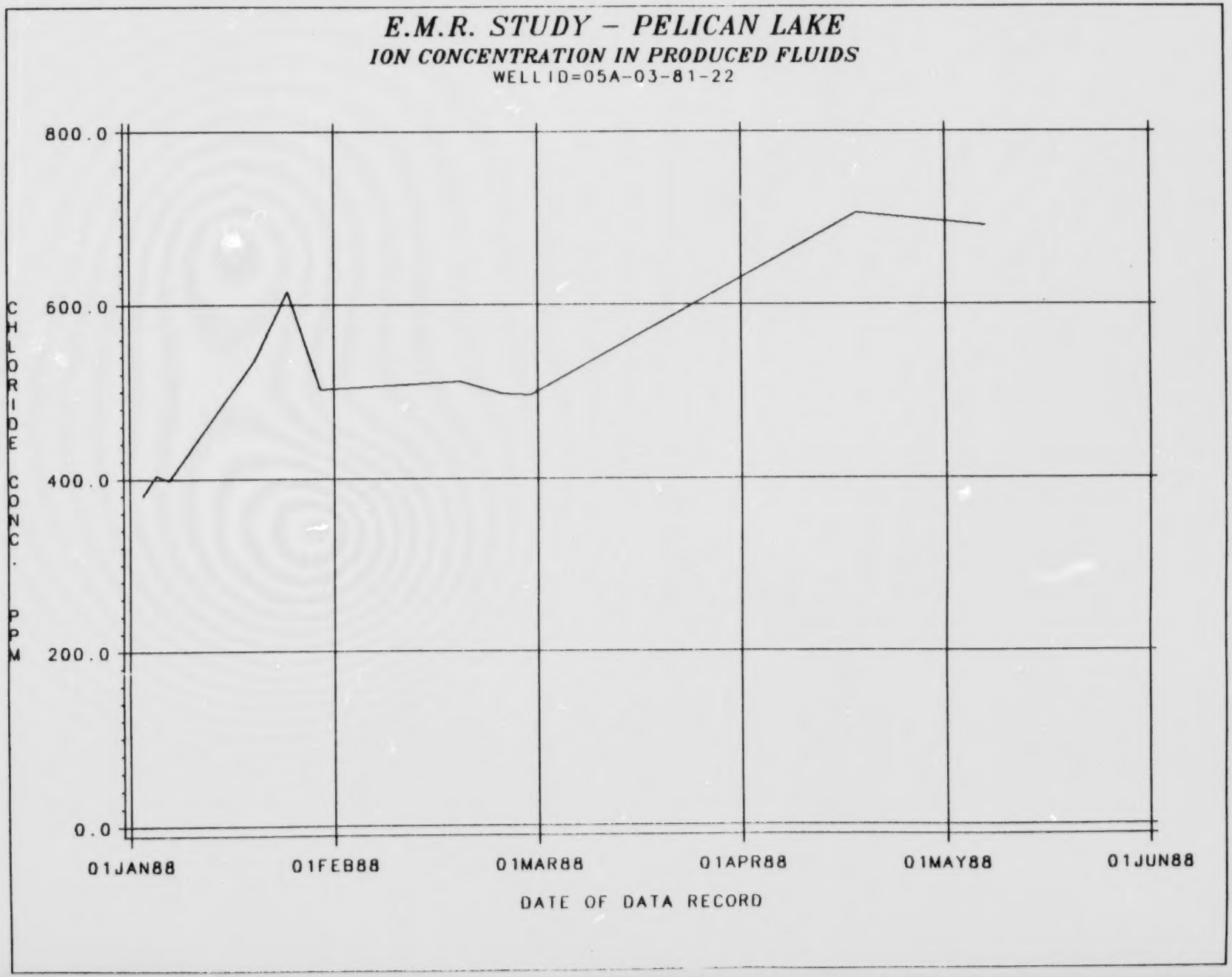

E.M.R. STUDY – PELICAN LAKE
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=05A-03-81-22
800.0
600.0
400.0
200.0
0.0
CHLORIDE CONC. PPM
01JAN88
01FEB88
01MAR88
01APR88
01MAY88
01JUN88
DATE OF DATA RECORD

FIGURE 60

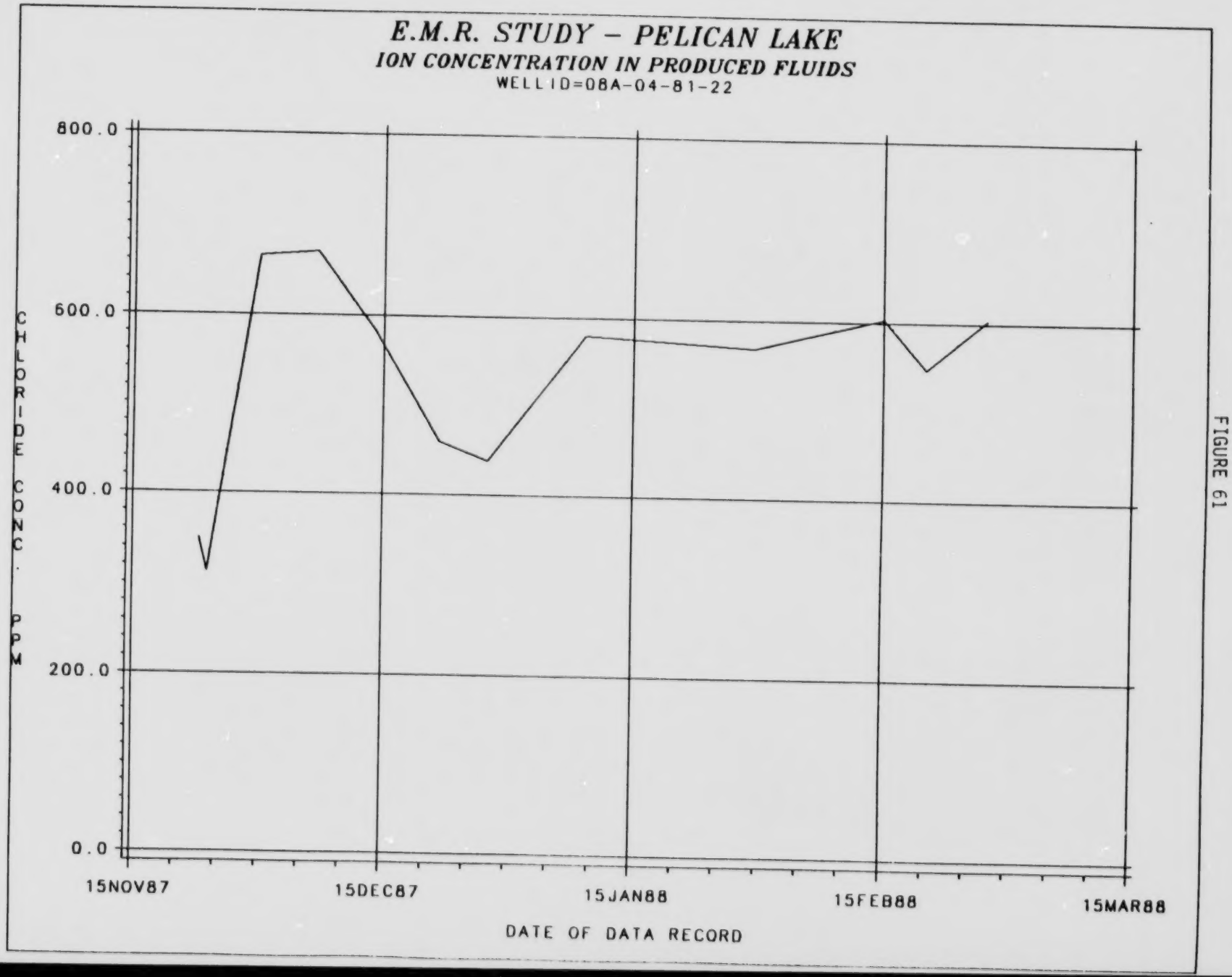
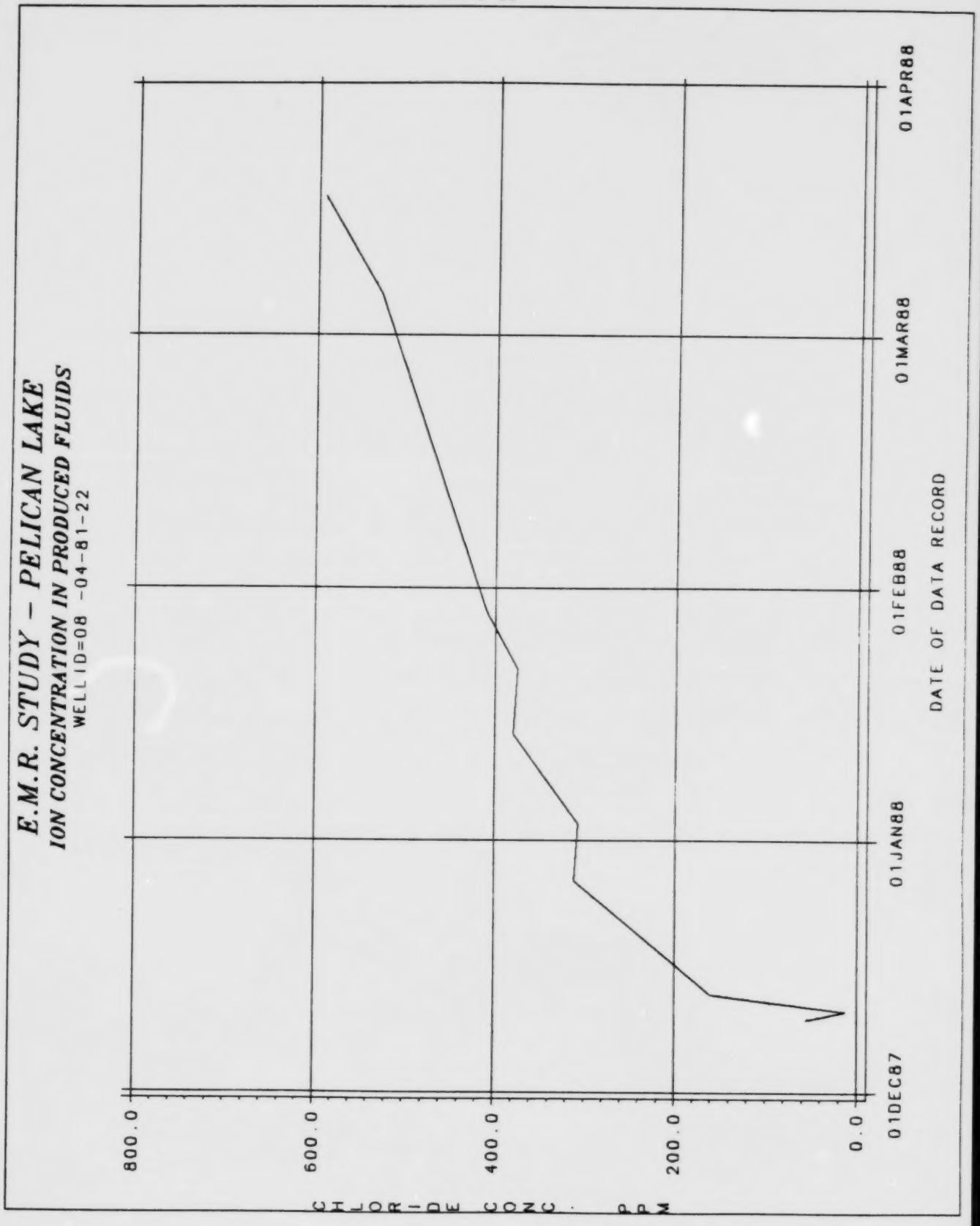

E.M.R. STUDY – PELICAN LAKE
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=08A-04-81-22
800.0
600.0
400.0
200.0
0.0
CHLORIDE CONC. PPM
15NOV87
15DEC87
15JAN88
15FEB88
15MAR88
DATE OF DATA RECORD

FIGURE 61

E.M.R. STUDY – PELICAN LAKE
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=12 -03-81-22
800.0
600.0
400.0
200.0
0.0
CHLORIDE CONC. PPM
01FEB88
01MAR88
01APR88
01MAY88
01JUN88
DATE OF DATA RECORD

FIGURE 62

FIGURE 63


E.M.R. STUDY – PELICAN LAKE
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=08 -04-81-22
CHLORIDE CONC. PPM
800.0
600.0
400.0
200.0
0.0
01DEC87
01JAN88
01FEB88
01MAR88
01APR88
DATE OF DATA RECORD

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=07 -17-81-22
SODIUM CONC. PPM
1000
900.00
800.00
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
15OCT87
15NOV87
15DEC87
15JAN88
15FEB88
DATE OF DATA RECORD

FIGURE 64

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=09 -17-81-22
1000
900.00
800.00
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
SODIUM CONC. PPM
01SEP87
01OCT87
01NOV87
01DEC87
01JAN88
DATE OF DATA RECORD

FIGURE 65

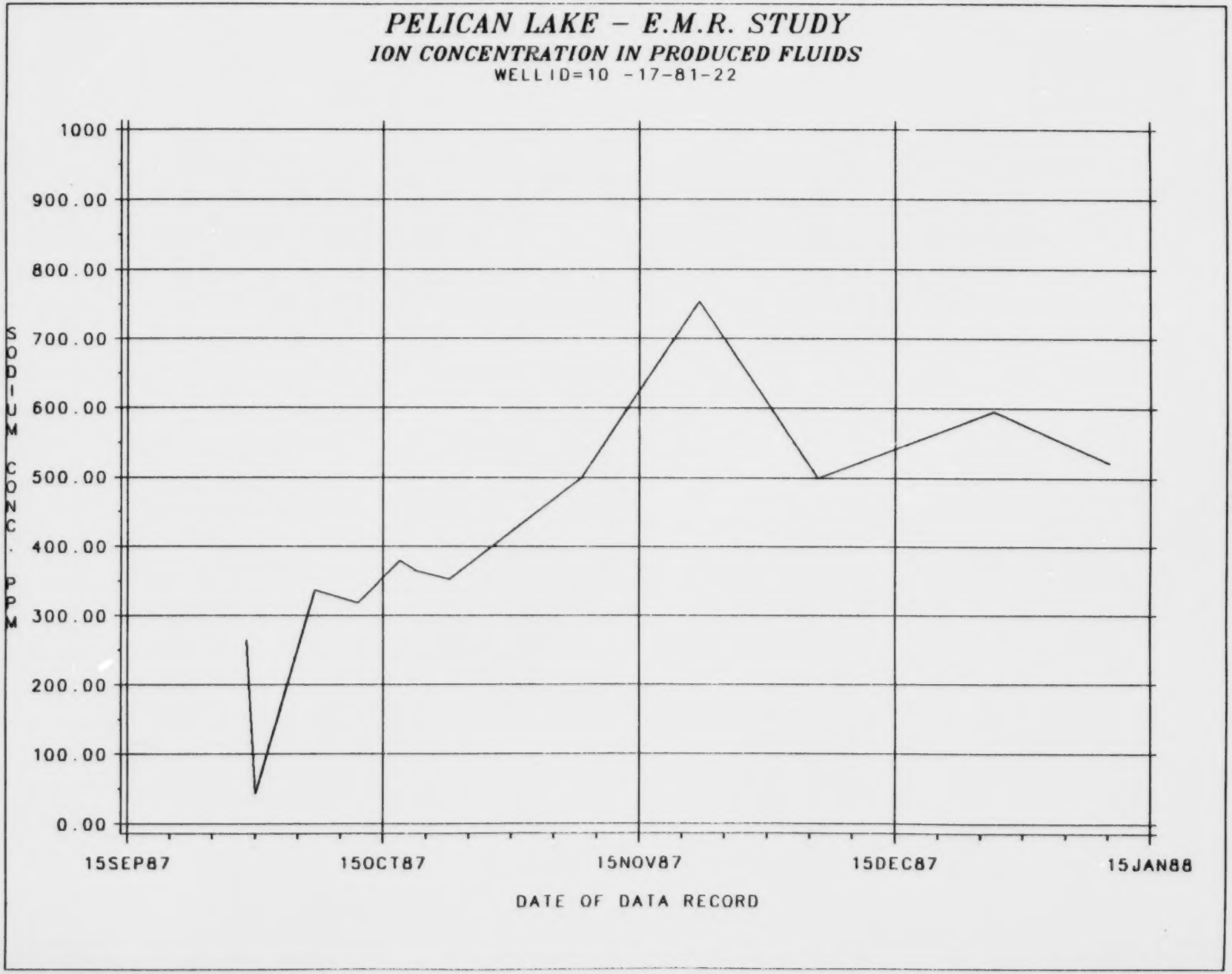
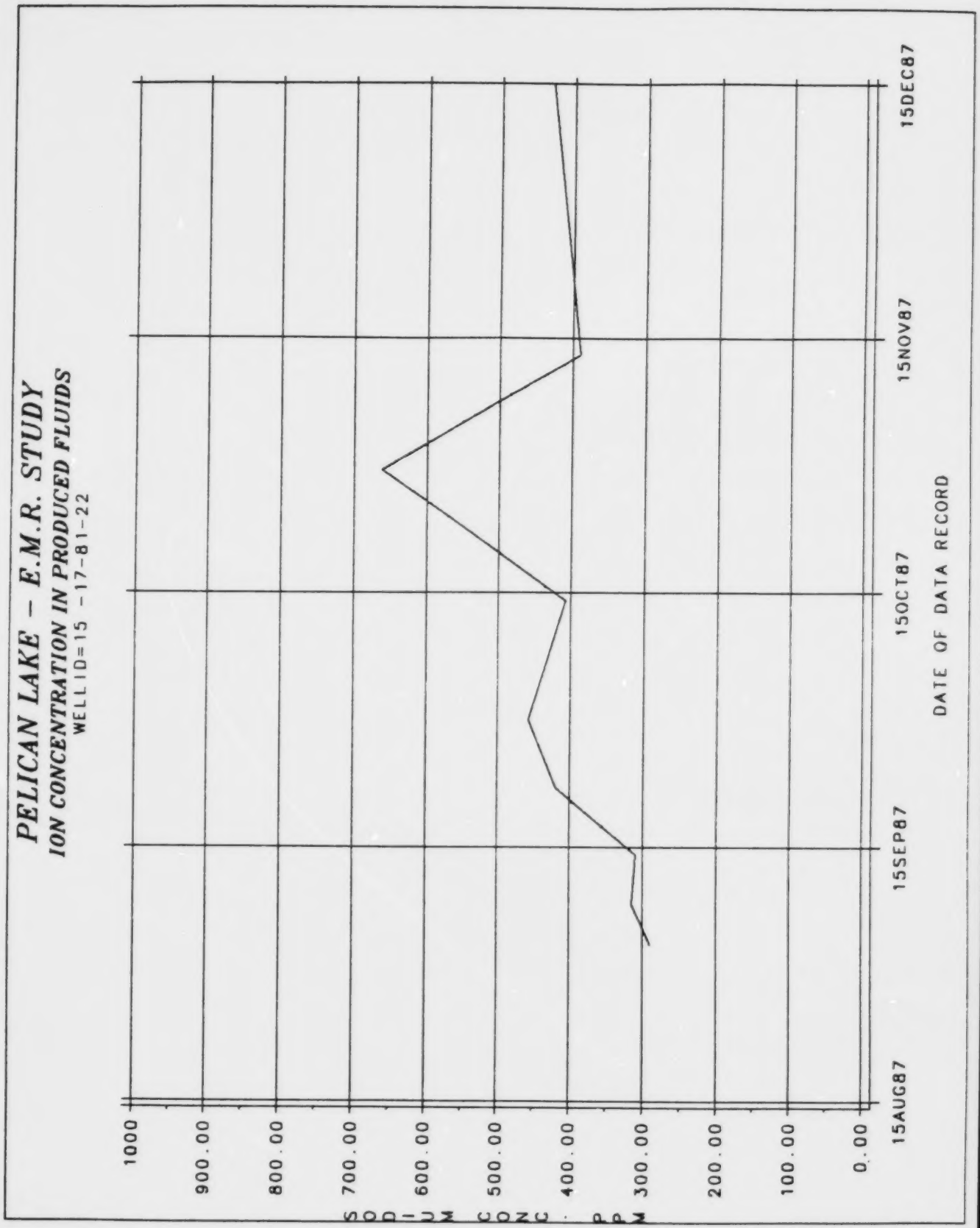

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=10 -17-81-22
1000
900.00
800.00
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
SODIUM CONC. PPM
15SEP87
15OCT87
15NOV87
15DEC87
15JAN88
DATE OF DATA RECORD

FIGURE 66

FIGURE 67


PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=15 -17-81-22
SODIUM CONC. PPM
1000
900.00
800.00
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
15AUG87
15SEP87
15OCT87
15NOV87
15DEC87
DATE OF DATA RECORD

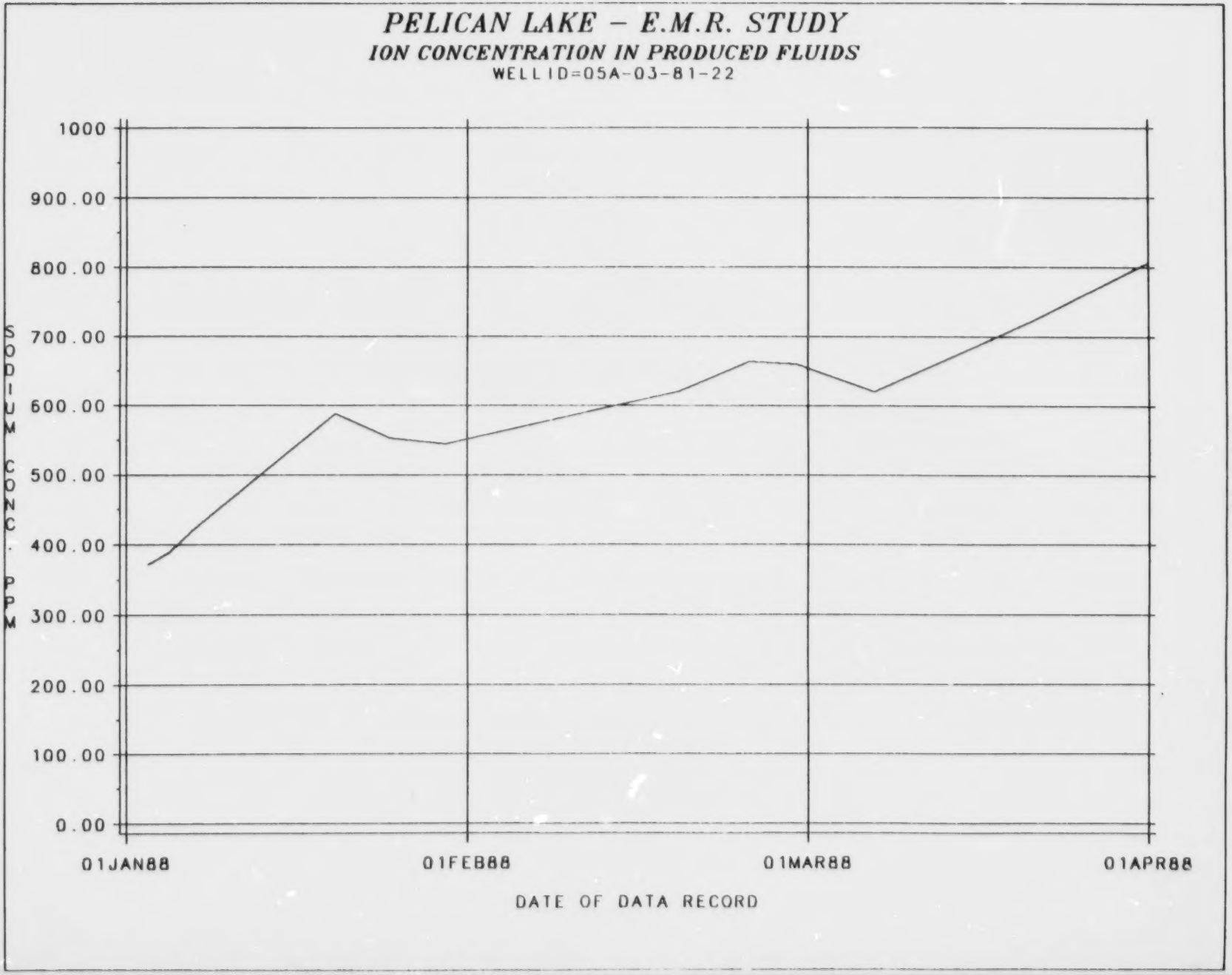

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=05A-03-81-22
1000
900.00
800.00
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
SODIUM CONC. PPM
01JAN88
01FEB88
01MAR88
01APR88
DATE OF DATA RECORD

FIGURE 68

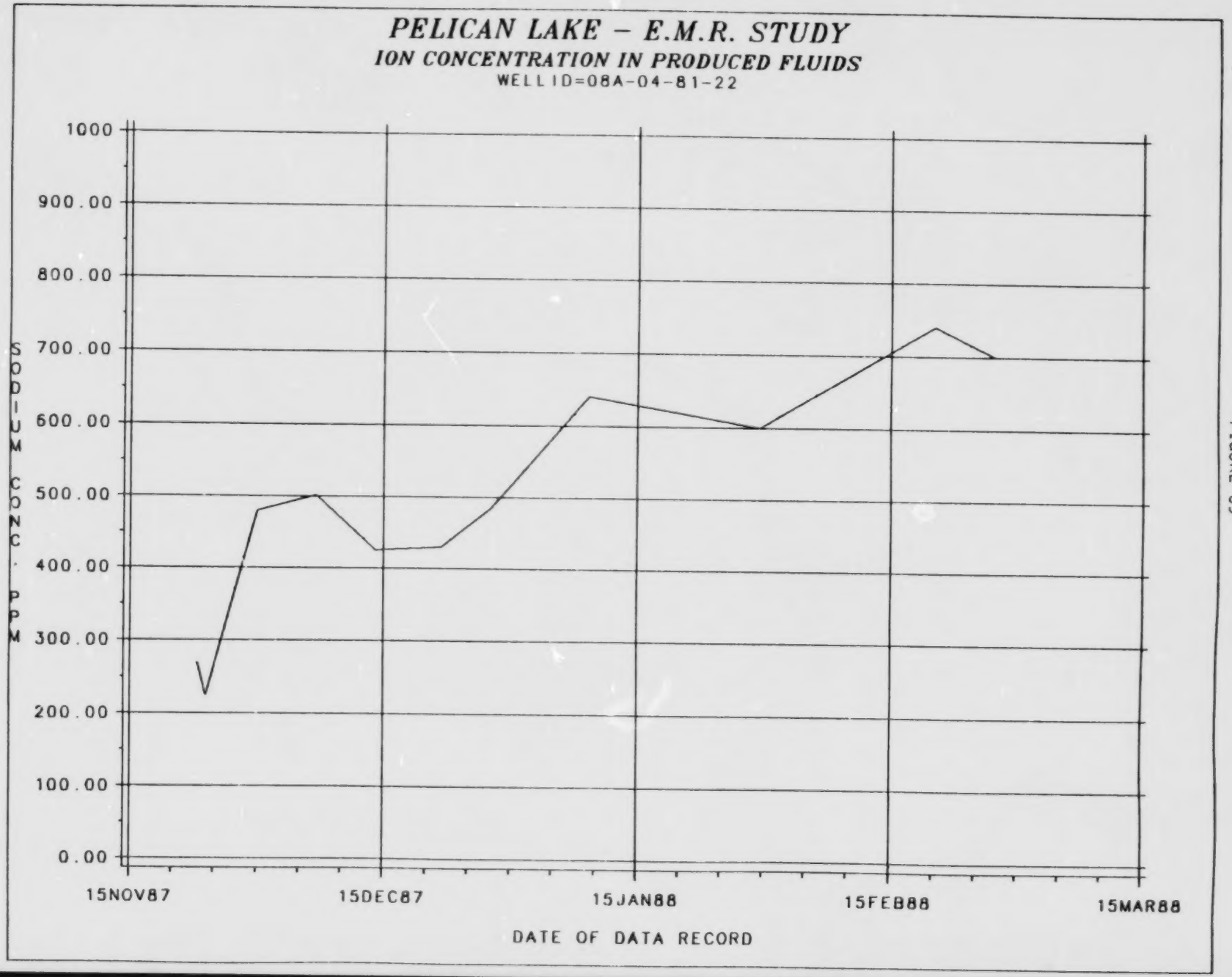
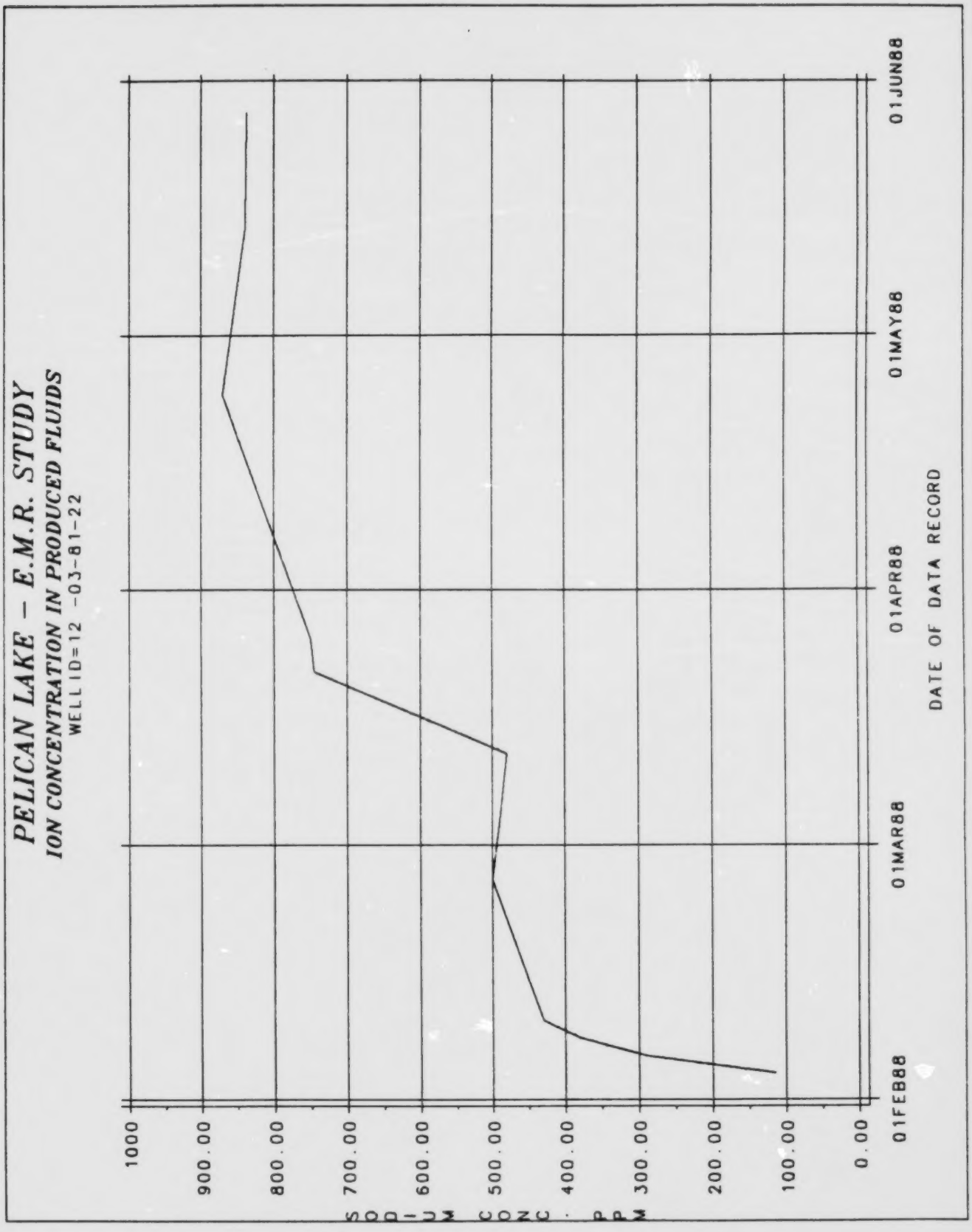

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=08A-04-81-22
1000
900.00
800.00
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
SOD-UM CONC. PPM
15NOV87
15DEC87
15JAN88
15FEB88
15MAR88
DATE OF DATA RECORD

FIGURE 69

FIGURE 70


PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELLID=12 -03-81-22
SODIUM CONC. PPM
1000
900.00
800.00
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
01FEB88
01MAR88
01APR88
01MAY88
01JUN88
DATE OF DATA RECORD

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=08 -04-81-22
1000
900.00
800.00
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
SOD-UM CONC. PPM
01DEC87
01JAN88
01FEB88
01MAR88
01APR88
DATE OF DATA RECORD

FIGURE 71

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=07 -17-81-22
1600.0
1400.0
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
BICARBONATE CONC. PPM
15OCT87
15NOV87
15DEC87
15JAN88
15FEB88
DATE OF DATA RECORD

FIGURE 72

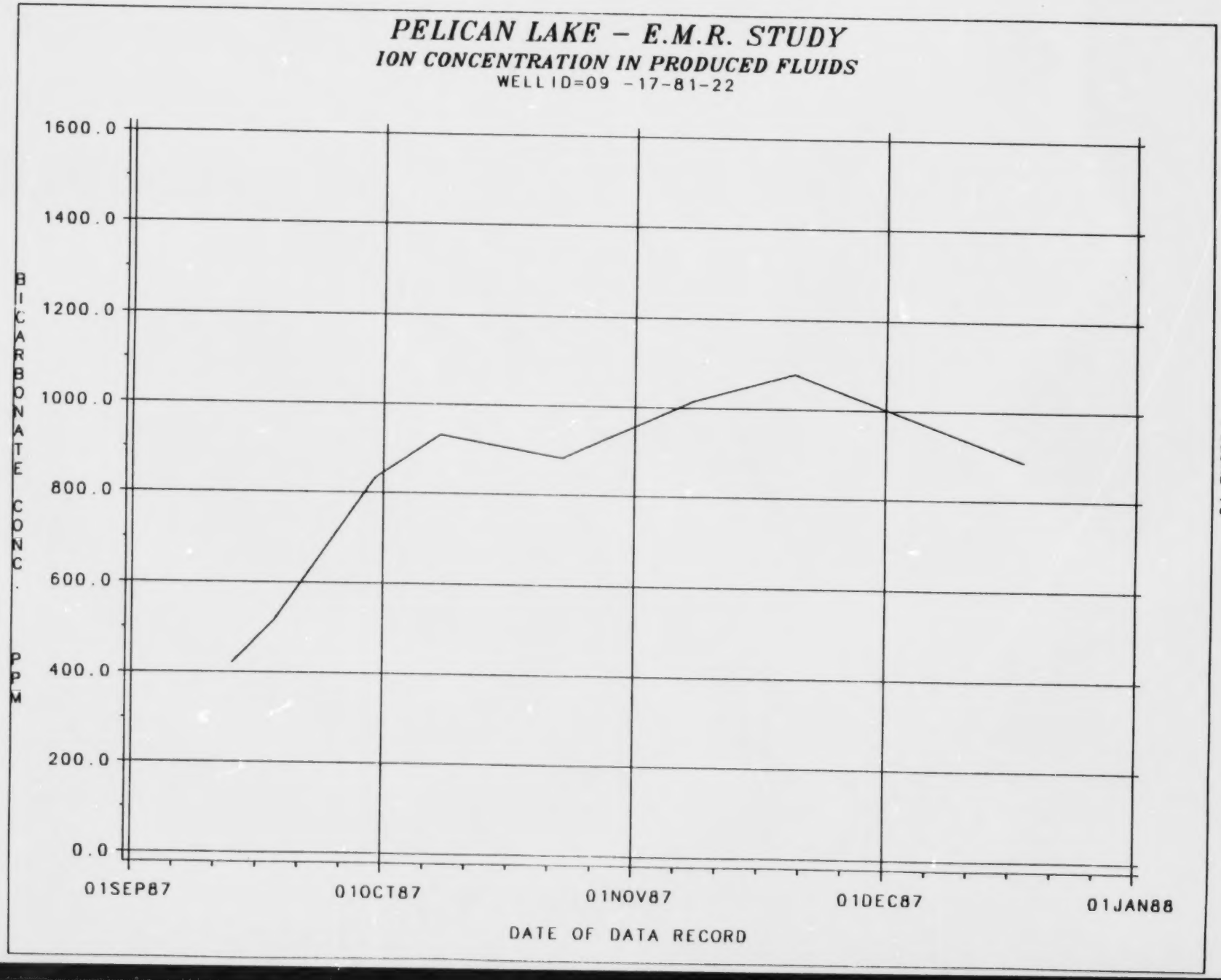

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=09 -17-81-22
1600.0
1400.0
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
BICARBONATE CONC. PPM
01SEP87
01OCT87
01NOV87
01DEC87
01JAN88
DATE OF DATA RECORD

FIGURE 73

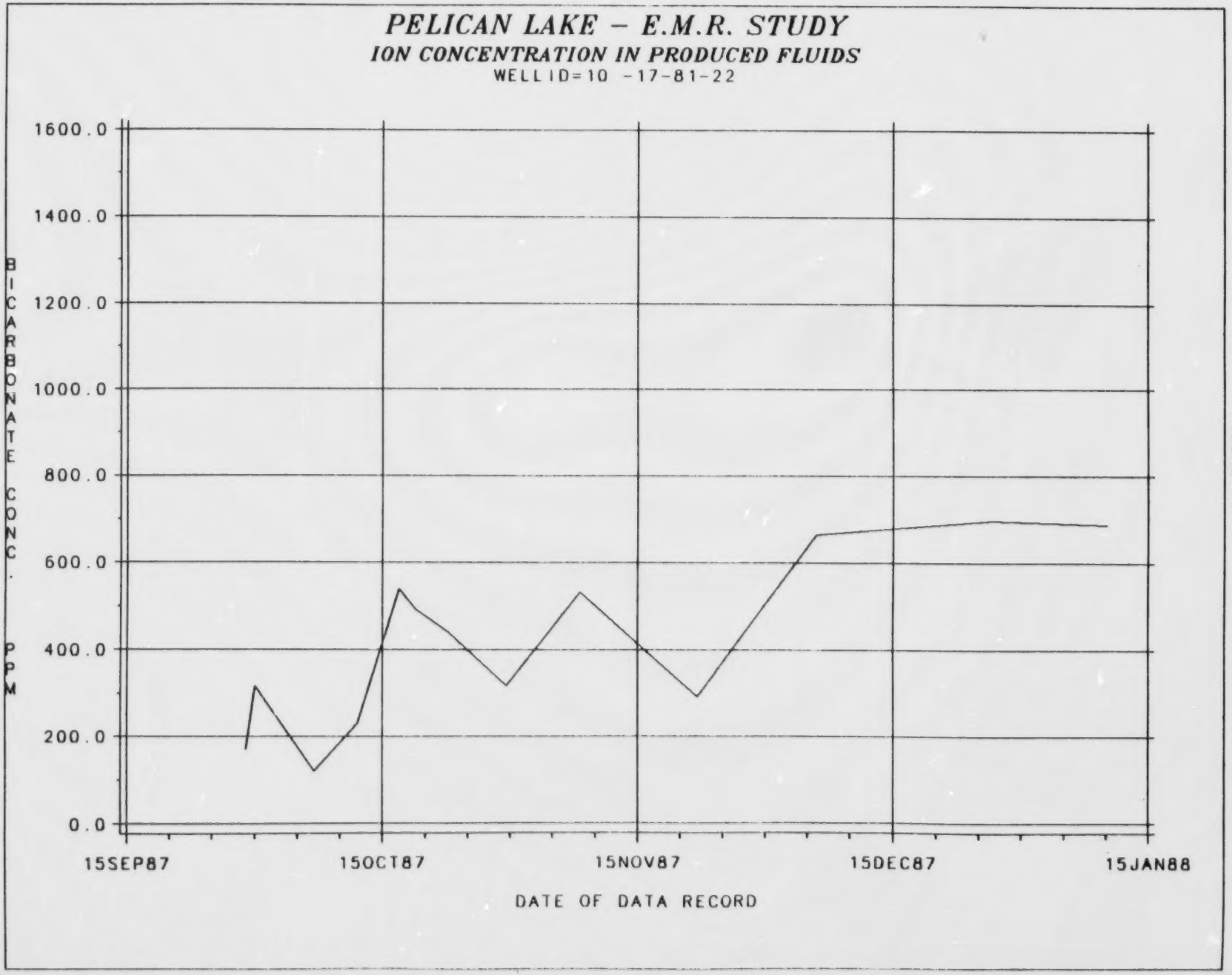

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=10 -17-81-22
1600.0
1400.0
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
BICARBONATE CONC. PPM
15SEP87
15OCT87
15NOV87
15DEC87
15JAN88
DATE OF DATA RECORD

FIGURE 74

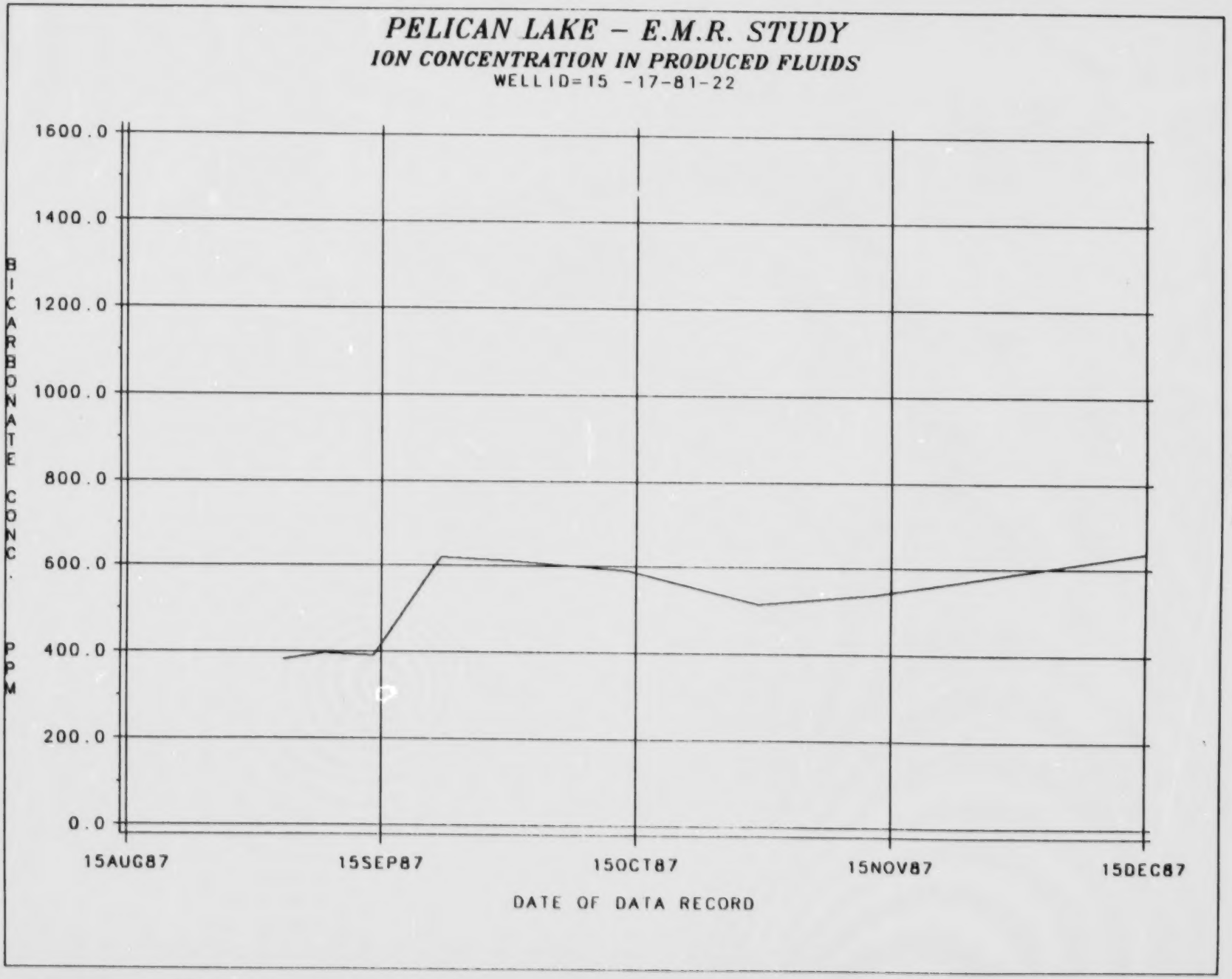
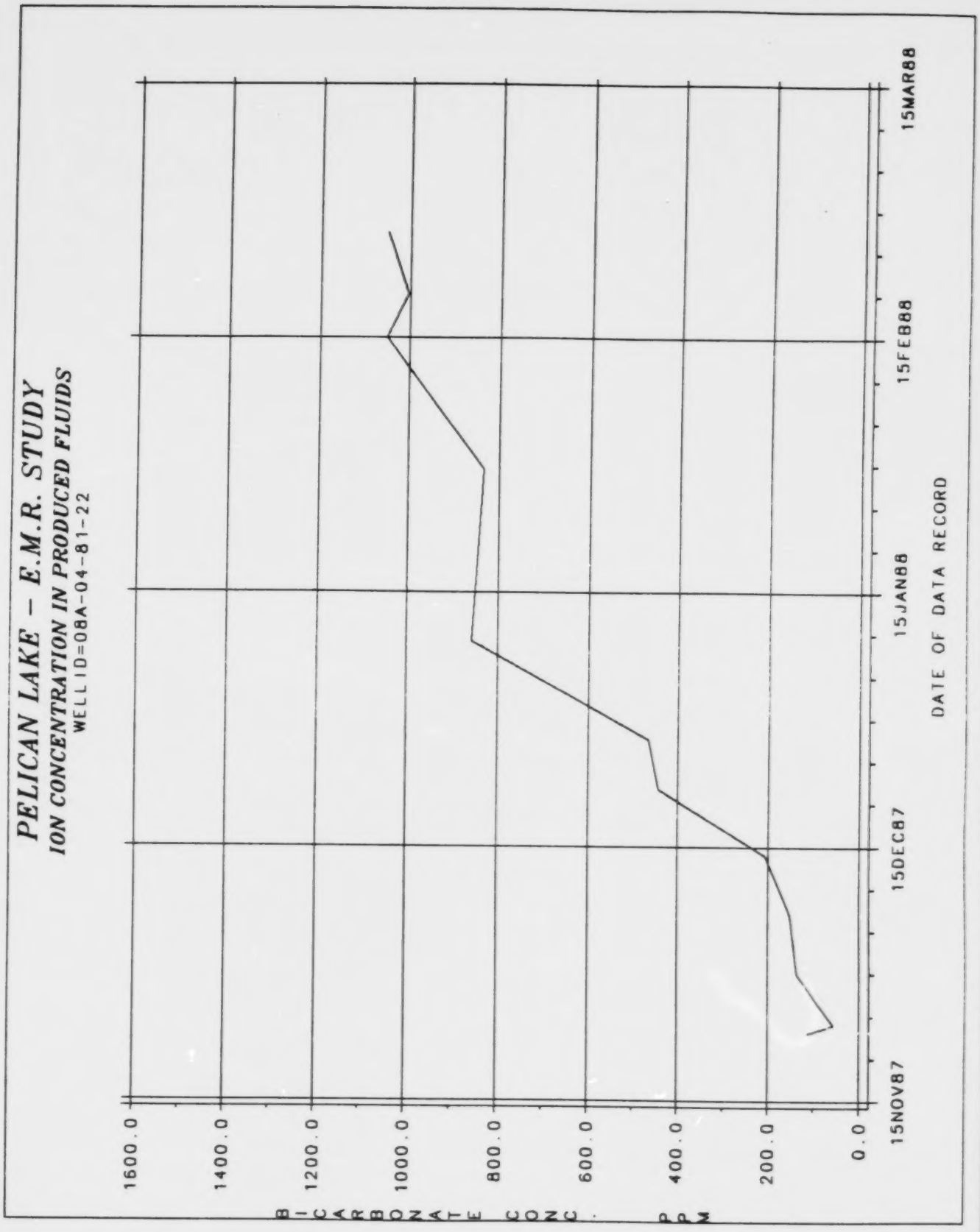

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=15 -17-81-22
1600.0
1400.0
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
BICARBONATE CONC. PPM
15AUG87
15SEP87
15OCT87
15NOV87
15DEC87
DATE OF DATA RECORD

FIGURE 75

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=05A-03-81-22
1600.0
1400.0
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
BICARBONATE CONC. PPM
01JAN88
01FEB88
01MAR88
01APR88
01MAY88
01JUN88
DATE OF DATA RECORD

FIGURE 76

FIGURE 77


PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELLID=08A-04-81-22
BI-CARBONATE CONC. PPM
1600.0
1400.0
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
15NOV87
15DEC87
15JAN88
15FEB88
15MAR88
DATE OF DATA RECORD

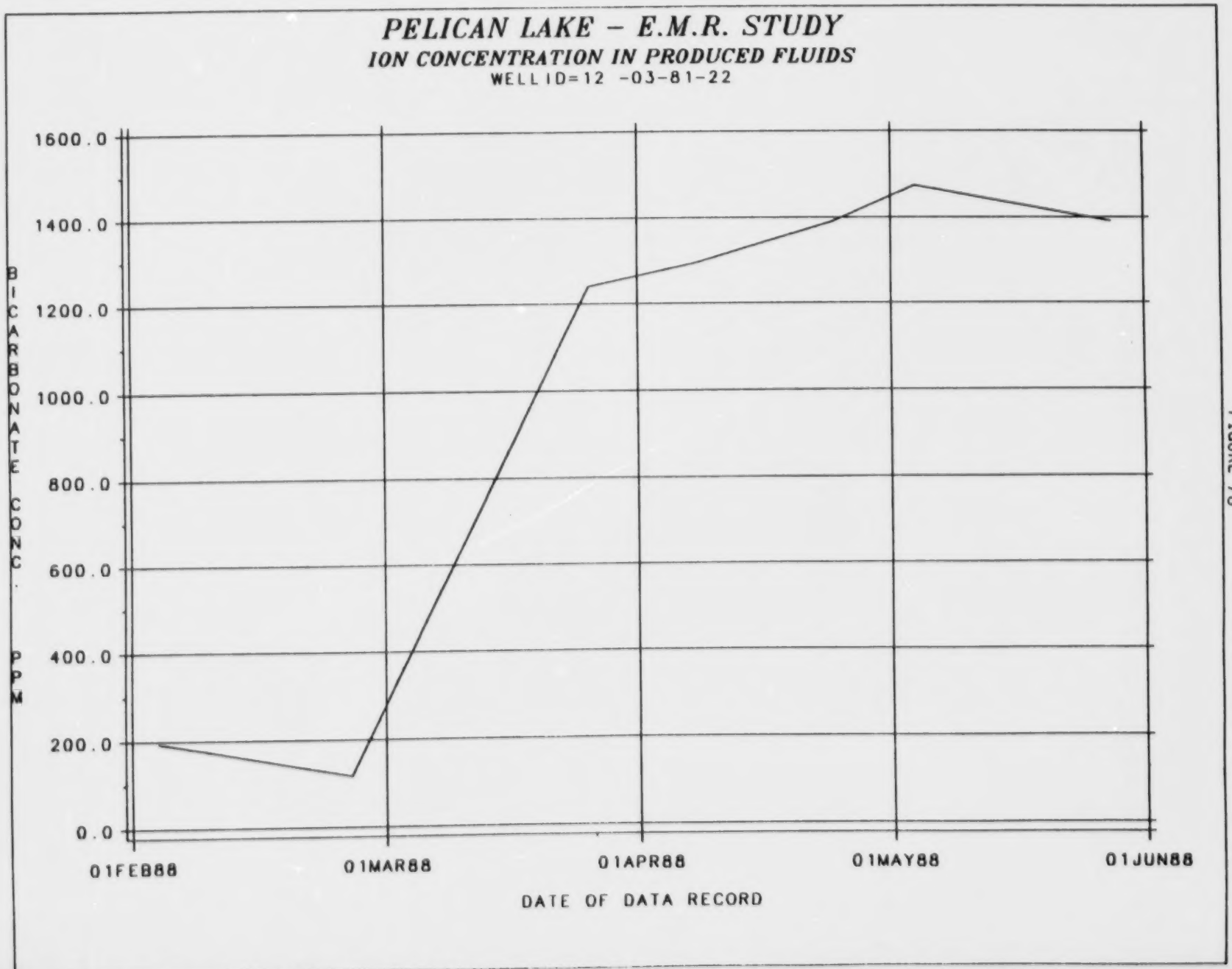
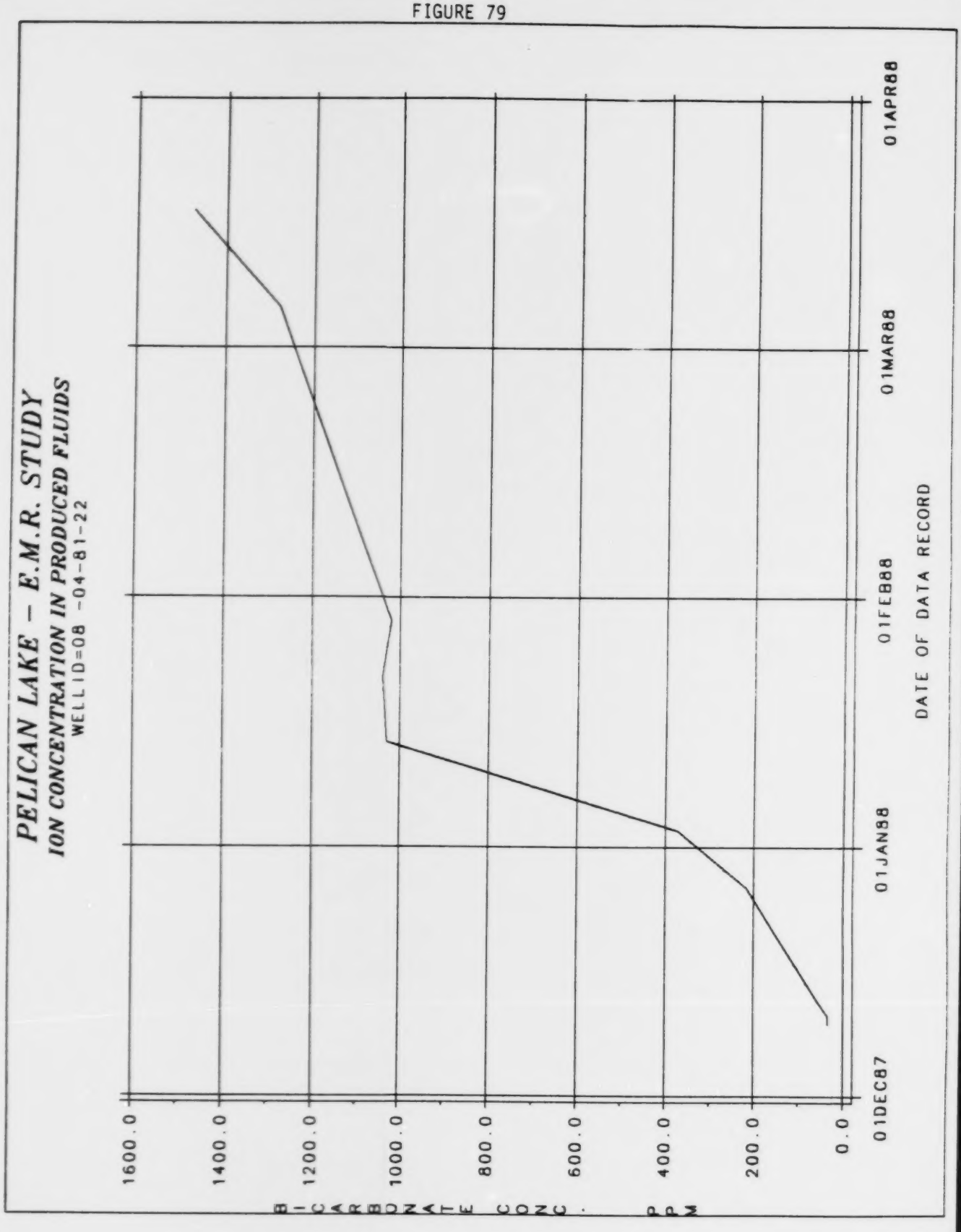

PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELL ID=12 -03-81-22
1600.0
1400.0
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
BICARBONATE CONC. PPM
01FEB88
01MAR88
01APR88
01MAY88
01JUN88
DATE OF DATA RECORD

FIGURE 78

FIGURE 79


PELICAN LAKE – E.M.R. STUDY
ION CONCENTRATION IN PRODUCED FLUIDS
WELLID=08 -04-81-22
BI-CARBONATE CONC. PPM
1600.0
1400.0
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
01DEC87
01JAN88
01FEB88
01MAR88
01APR88
DATE OF DATA RECORD

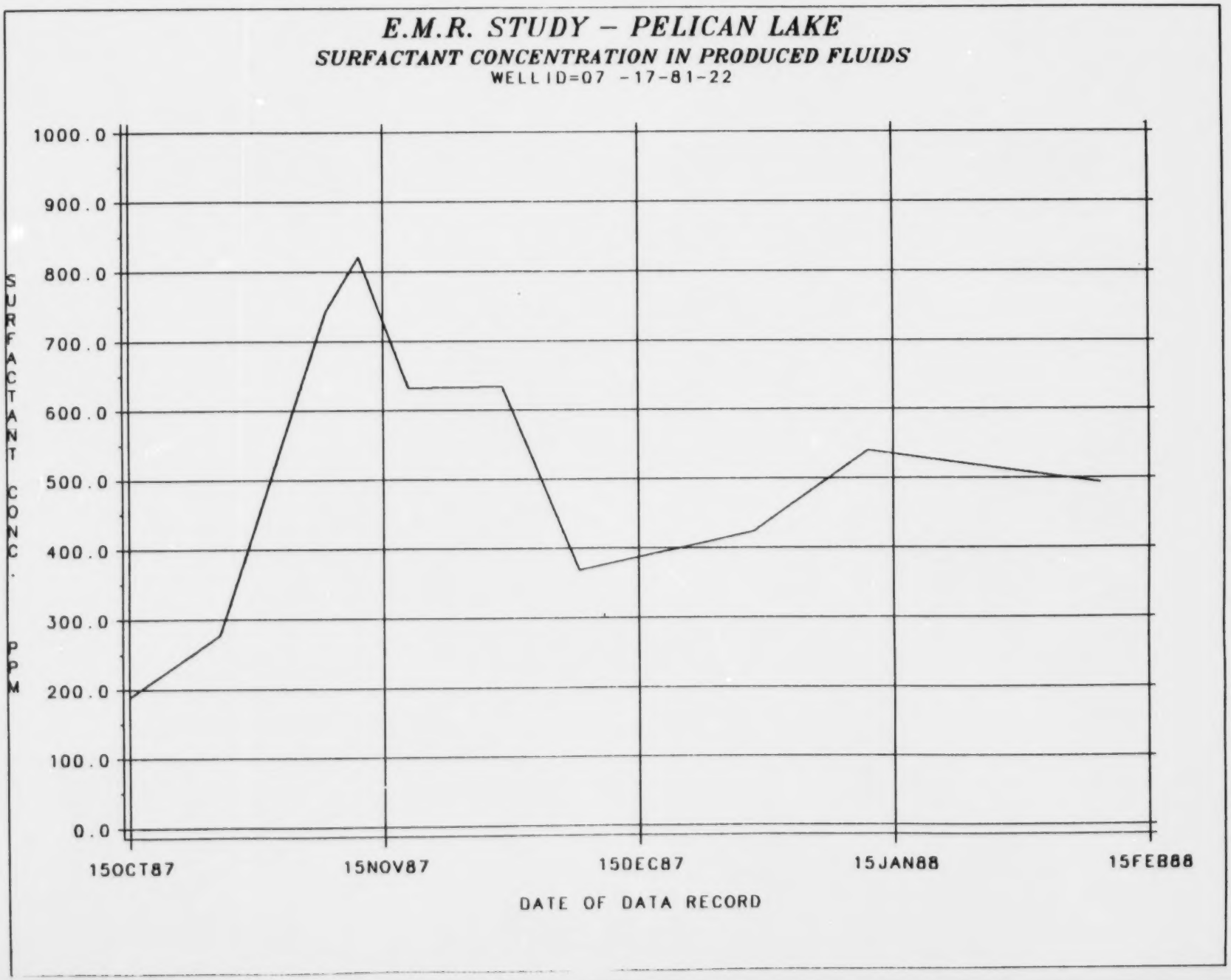
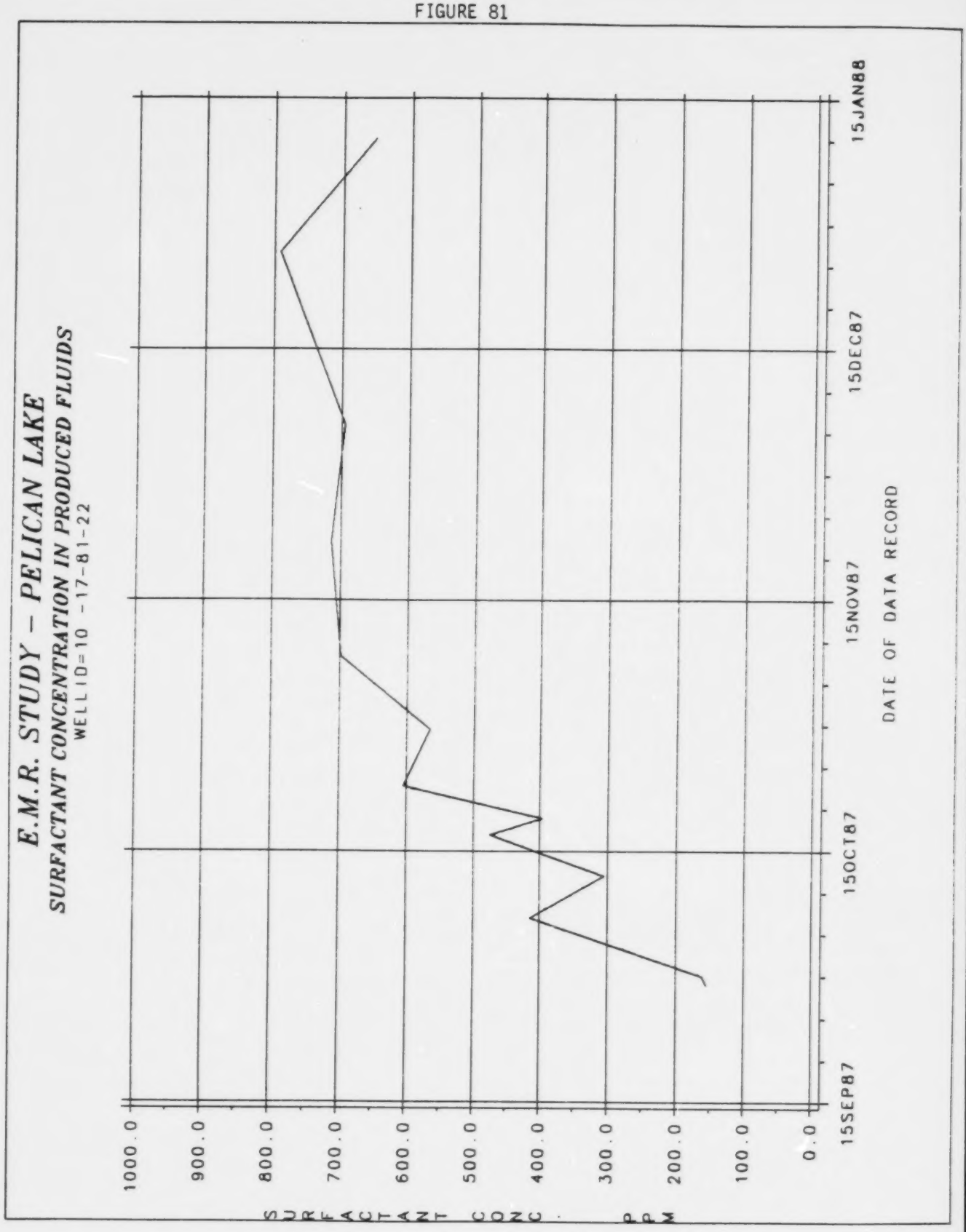

E.M.R. STUDY – PELICAN LAKE
SURFACTANT CONCENTRATION IN PRODUCED FLUIDS
WELL ID=07 -17-81-22
1000.0
900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.0
SURFACTANT CONC. PPM
15OCT87
15NOV87
15DEC87
15JAN88
15FEB88
DATE OF DATA RECORD

FIGURE 80

FIGURE 81


E.M.R. STUDY – PELICAN LAKE
SURFACTANT CONCENTRATION IN PRODUCED FLUIDS
WELL ID=10 -17-81-22
SURFACTANT CONC. PPM
1000.0
900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.0
15SEP87
15OCT87
15NOV87
15DEC87
15JAN88
DATE OF DATA RECORD

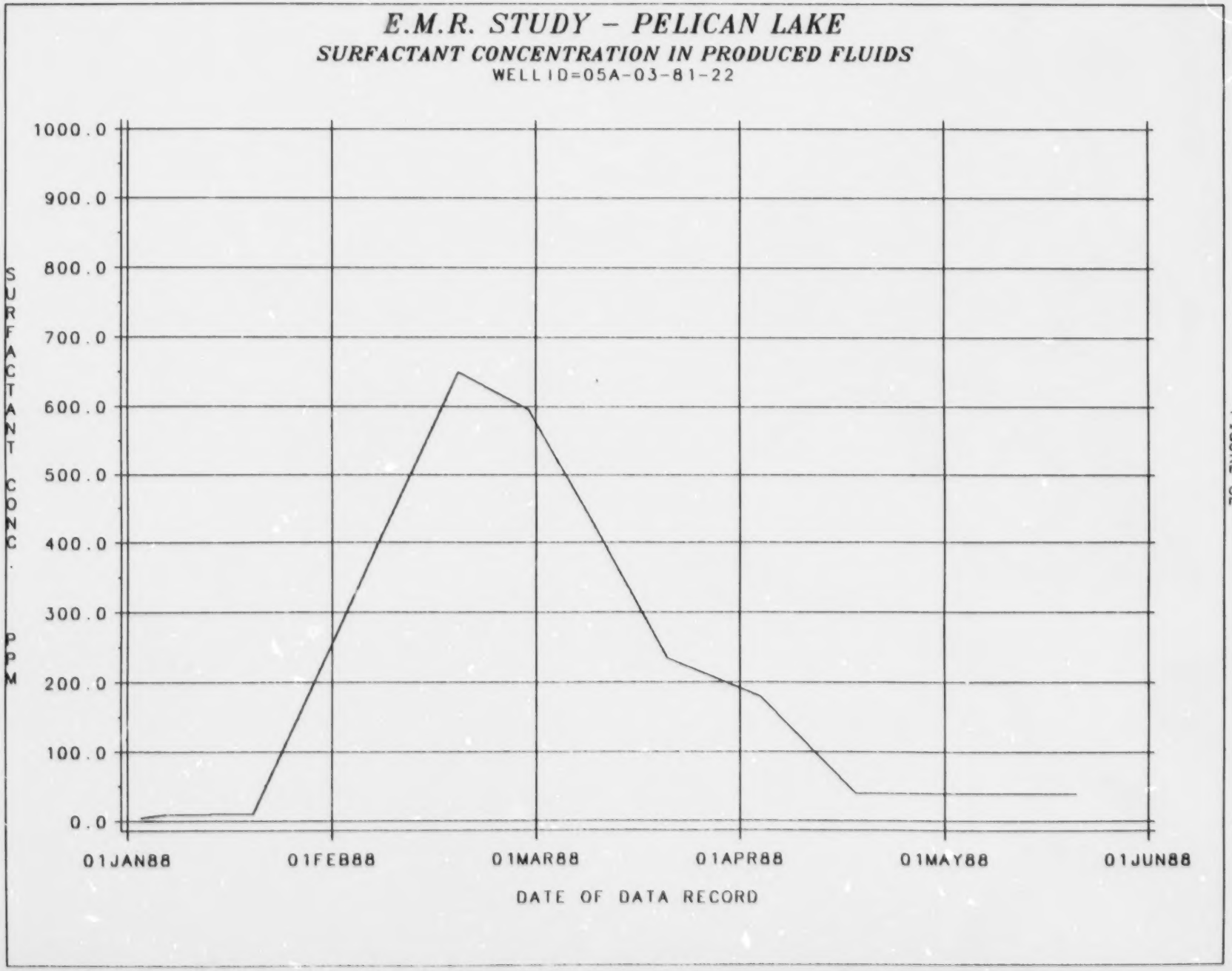
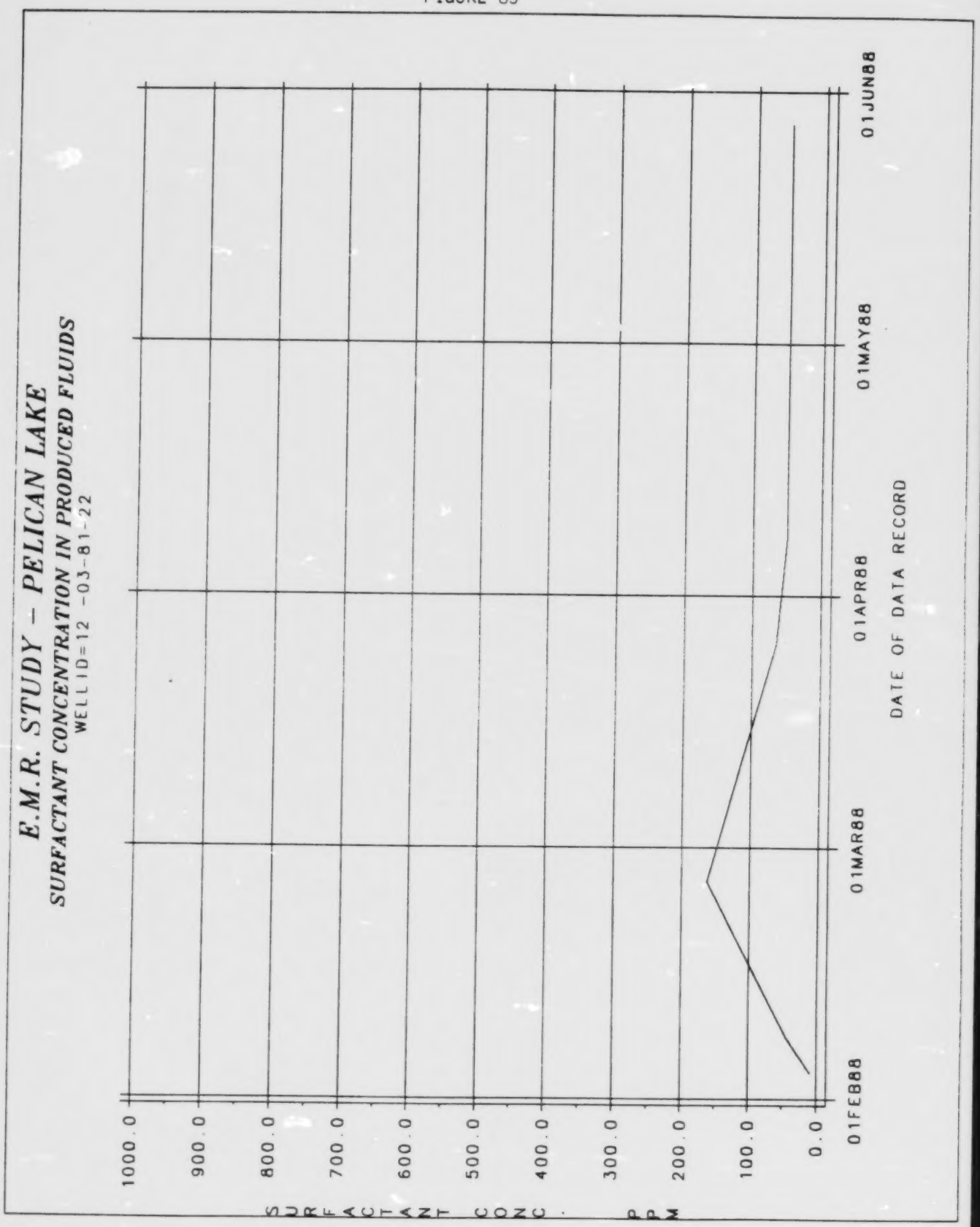

E.M.R. STUDY – PELICAN LAKE
SURFACTANT CONCENTRATION IN PRODUCED FLUIDS
WELL ID=05A-03-81-22
1000.0
900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.0
SURFACTANT CONC. PPM
01JAN88
01FEB88
01MAR88
01APR88
01MAY88
01JUN88
DATE OF DATA RECORD

FIGURE 82

FIGURE 83


E.M.R. STUDY – PELICAN LAKE
SURFACTANT CONCENTRATION IN PRODUCED FLUIDS
WELLID=12 -03-81-22
SURFACTANT CONC. PPM
1000.0
900.0
800.0
700.0
600.0
500.0
400.0
300.0
200.0
100.0
0.0
01FEB88
01MAR88
01APR88
01MAY88
01JUN88
DATE OF DATA RECORD

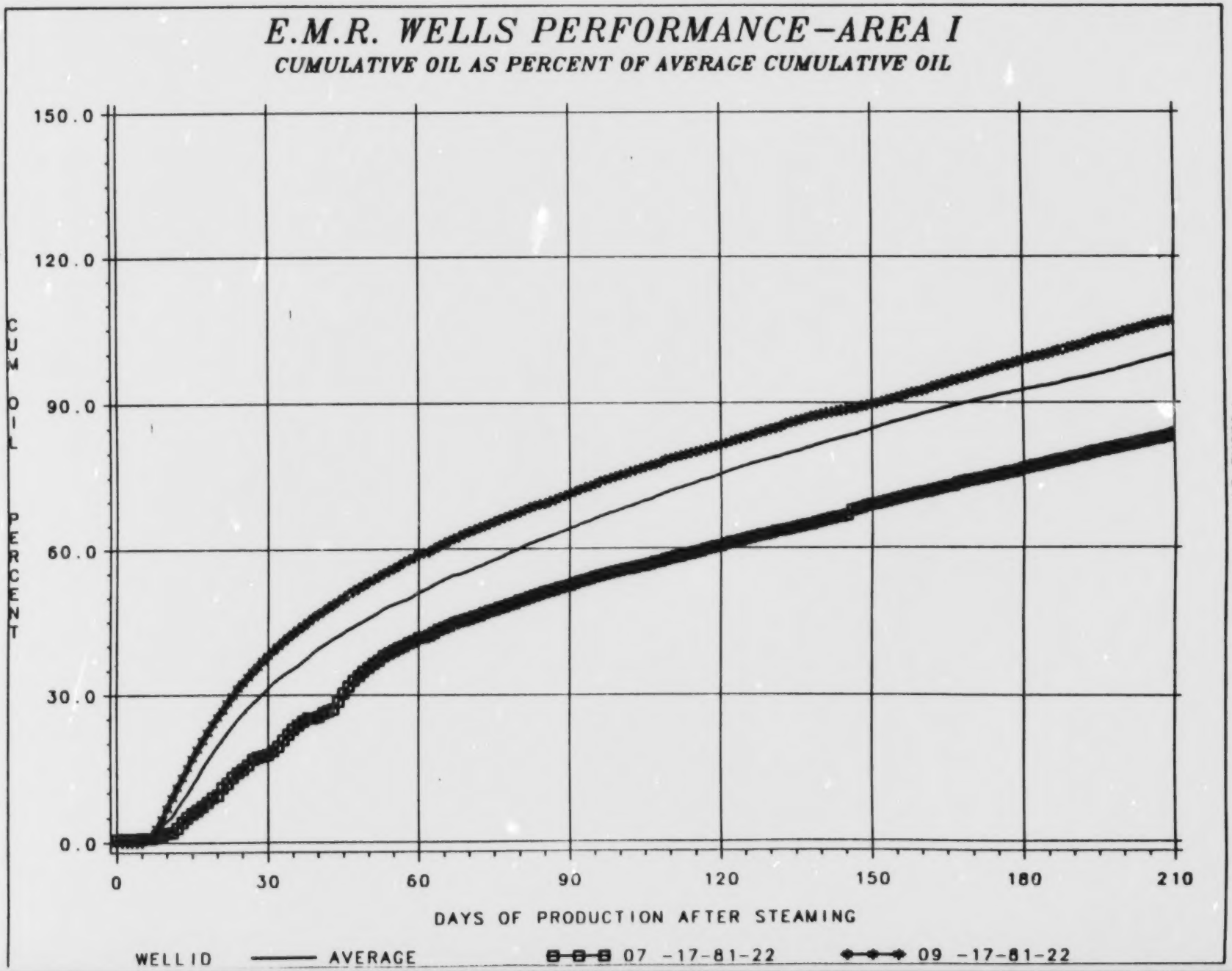

E.M.R. WELLS PERFORMANCE–AREA I
CUMULATIVE OIL AS PERCENT OF AVERAGE CUMULATIVE OIL
150.0
120.0
90.0
60.0
30.0
0.0
CUM OIL PERCENT
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
WELL ID
AVERAGE
07 -17-81-22
09 -17-81-22

FIGURE 84

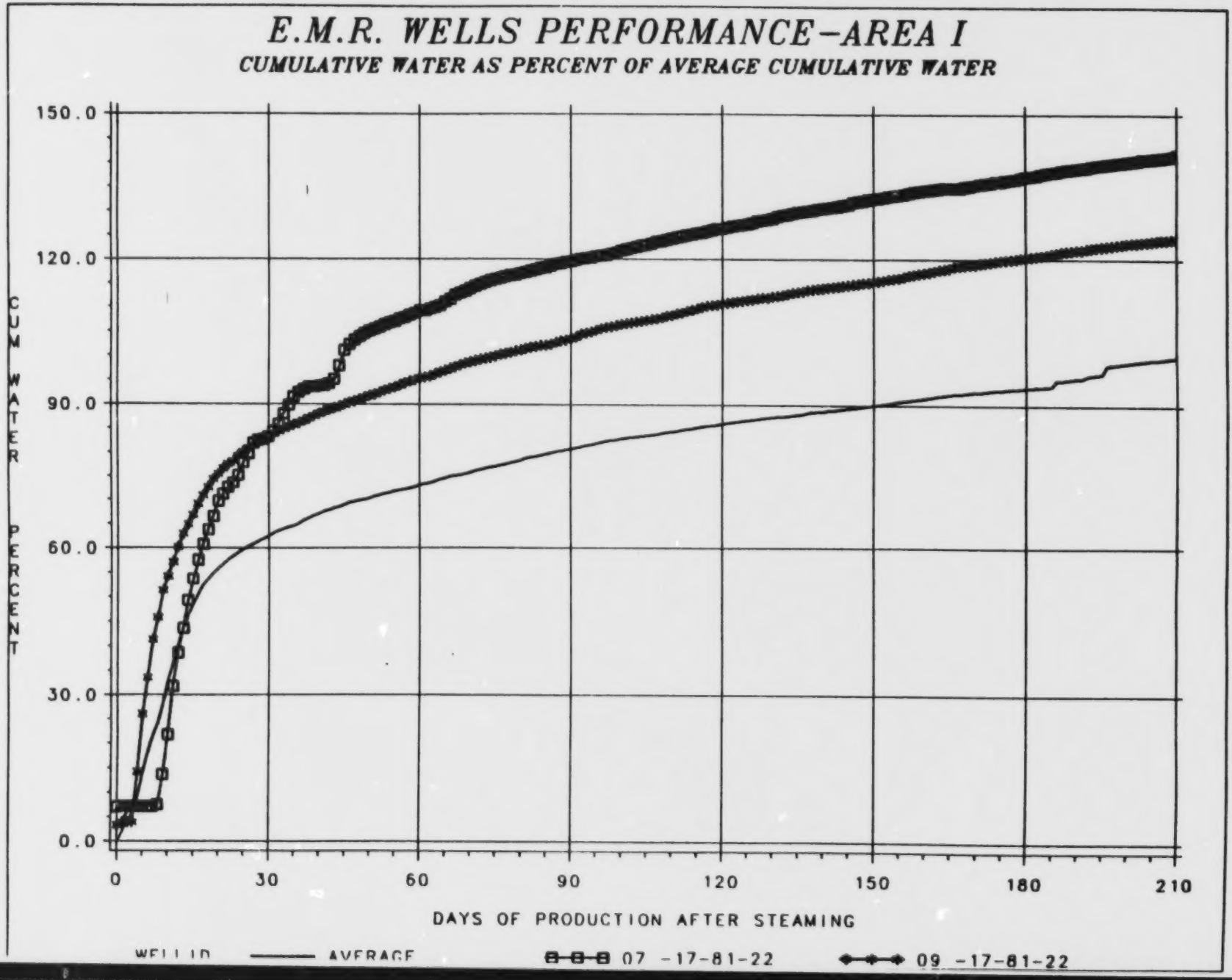
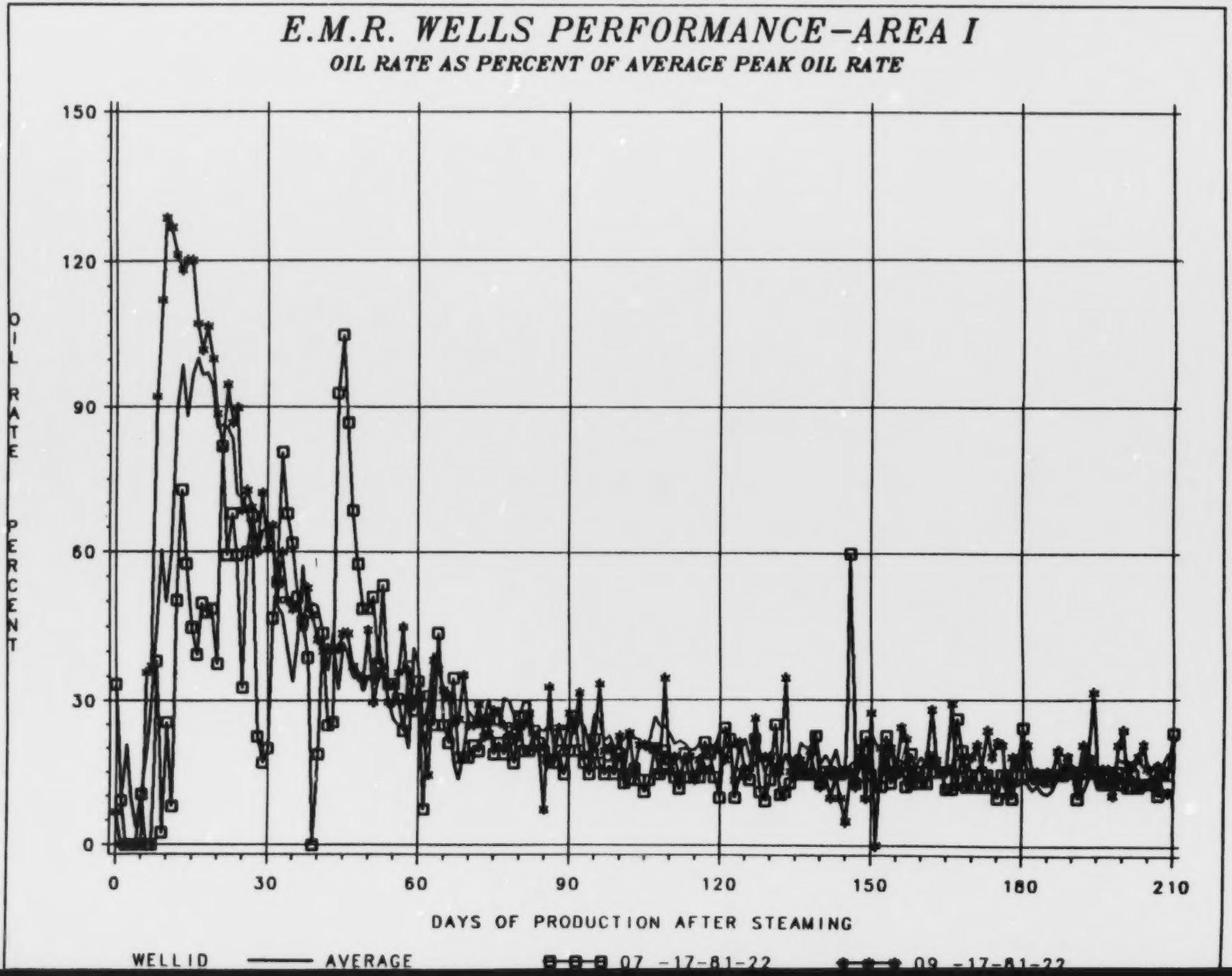

E.M.R. WELLS PERFORMANCE–AREA I
CUMULATIVE WATER AS PERCENT OF AVERAGE CUMULATIVE WATER
CUM WATER PERCENT
150.0
120.0
90.0
60.0
30.0
0.0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
WELL ID
AVERAGE
07 -17-81-22
09 -17-81-22

FIGURE 85


E.M.R. WELLS PERFORMANCE–AREA I
OIL RATE AS PERCENT OF AVERAGE PEAK OIL RATE
OIL RATE PERCENT
150
120
90
60
30
0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
WELL ID
AVERAGE
07 -17-81-22
09 -17-81-22

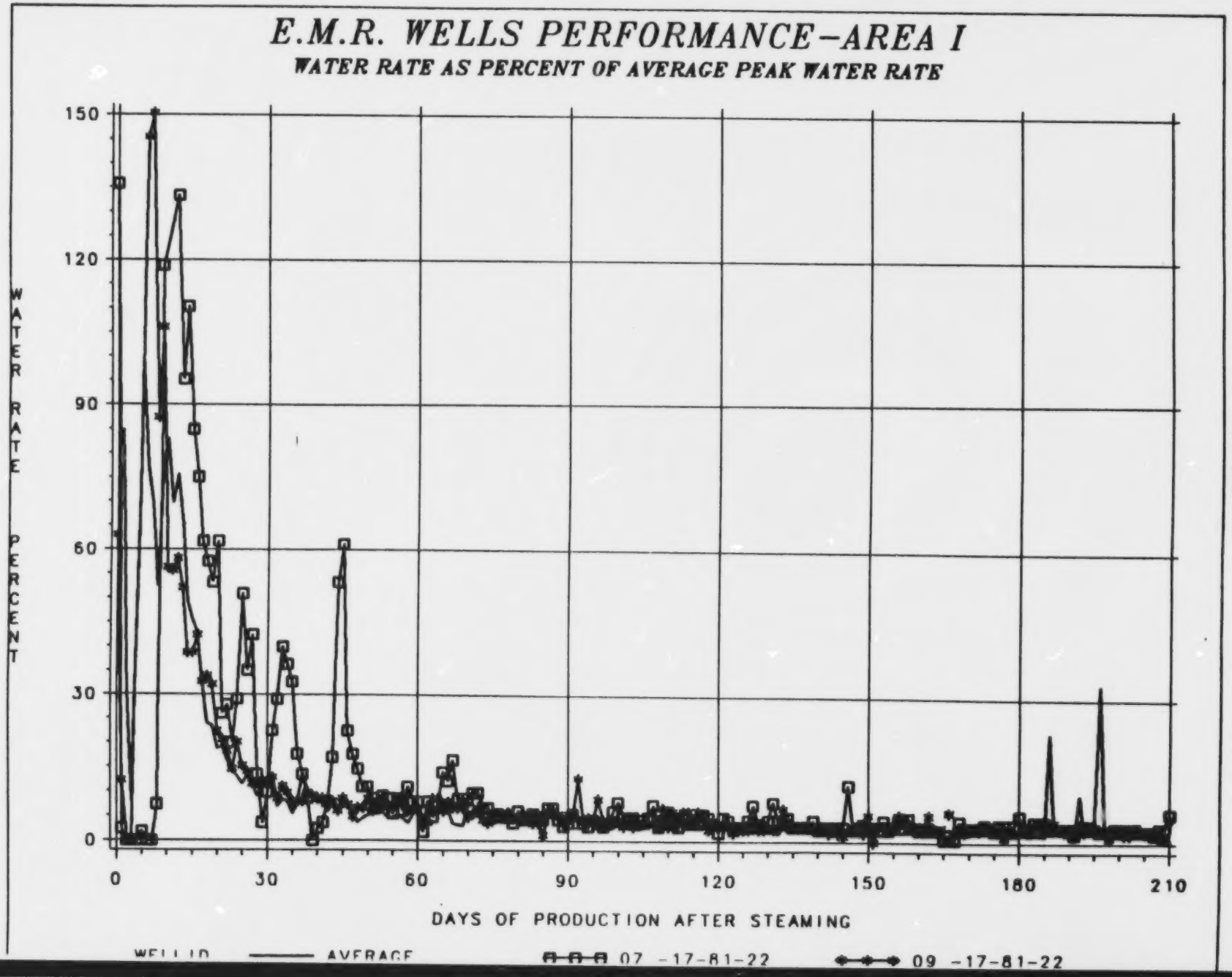

E.M.R. WELLS PERFORMANCE–AREA I
WATER RATE AS PERCENT OF AVERAGE PEAK WATER RATE
WATER RATE PERCENT
150
120
90
60
30
0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
WELL ID
AVERAGE
07 -17-81-22
09 -17-81-22

FIGURE 87

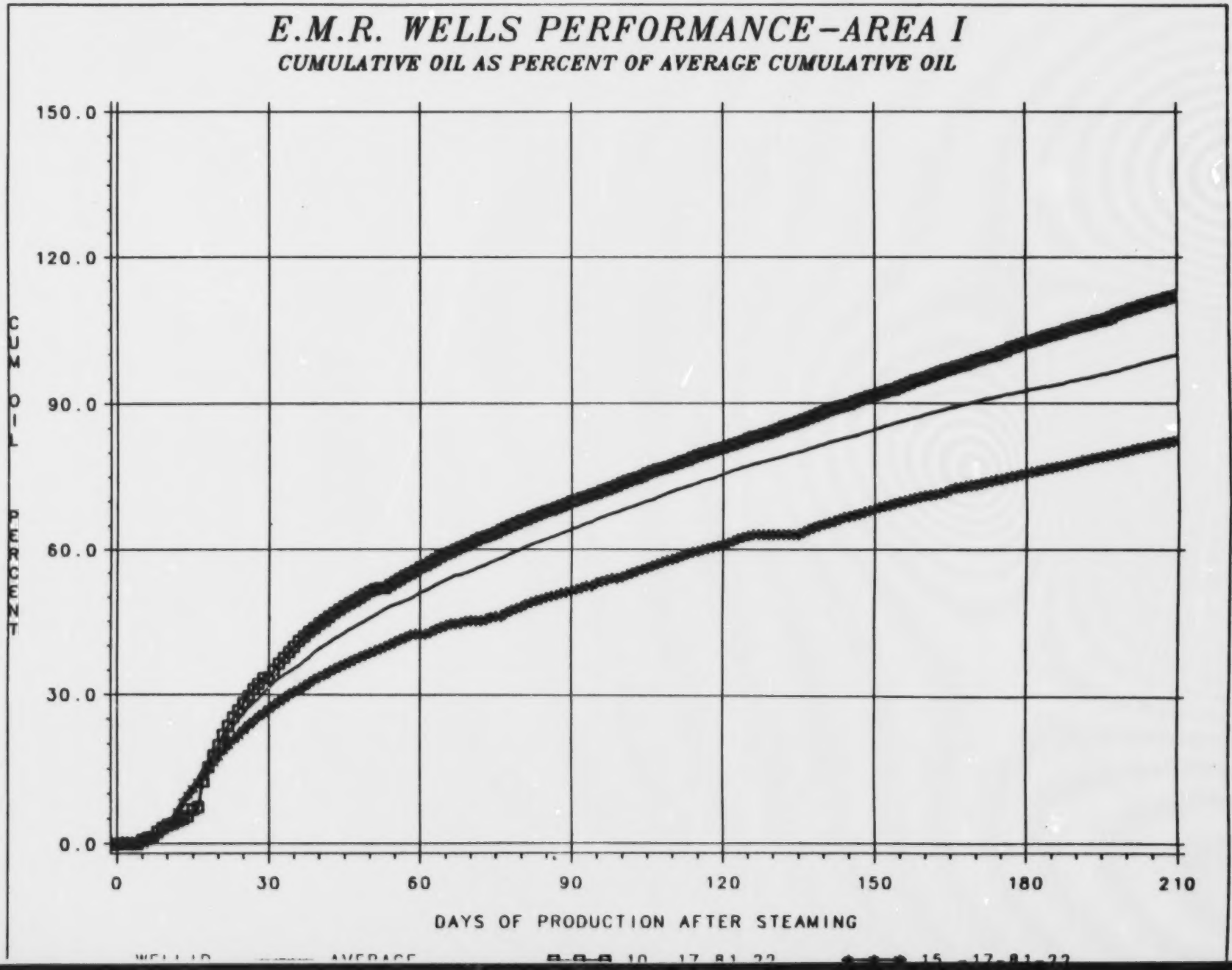

E.M.R. WELLS PERFORMANCE-AREA I
CUMULATIVE OIL AS PERCENT OF AVERAGE CUMULATIVE OIL
150.0
120.0
90.0
60.0
30.0
0.0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
AVERAGE
10, 17, 81, 22
15, 17, 81, 22

FIGURE 88

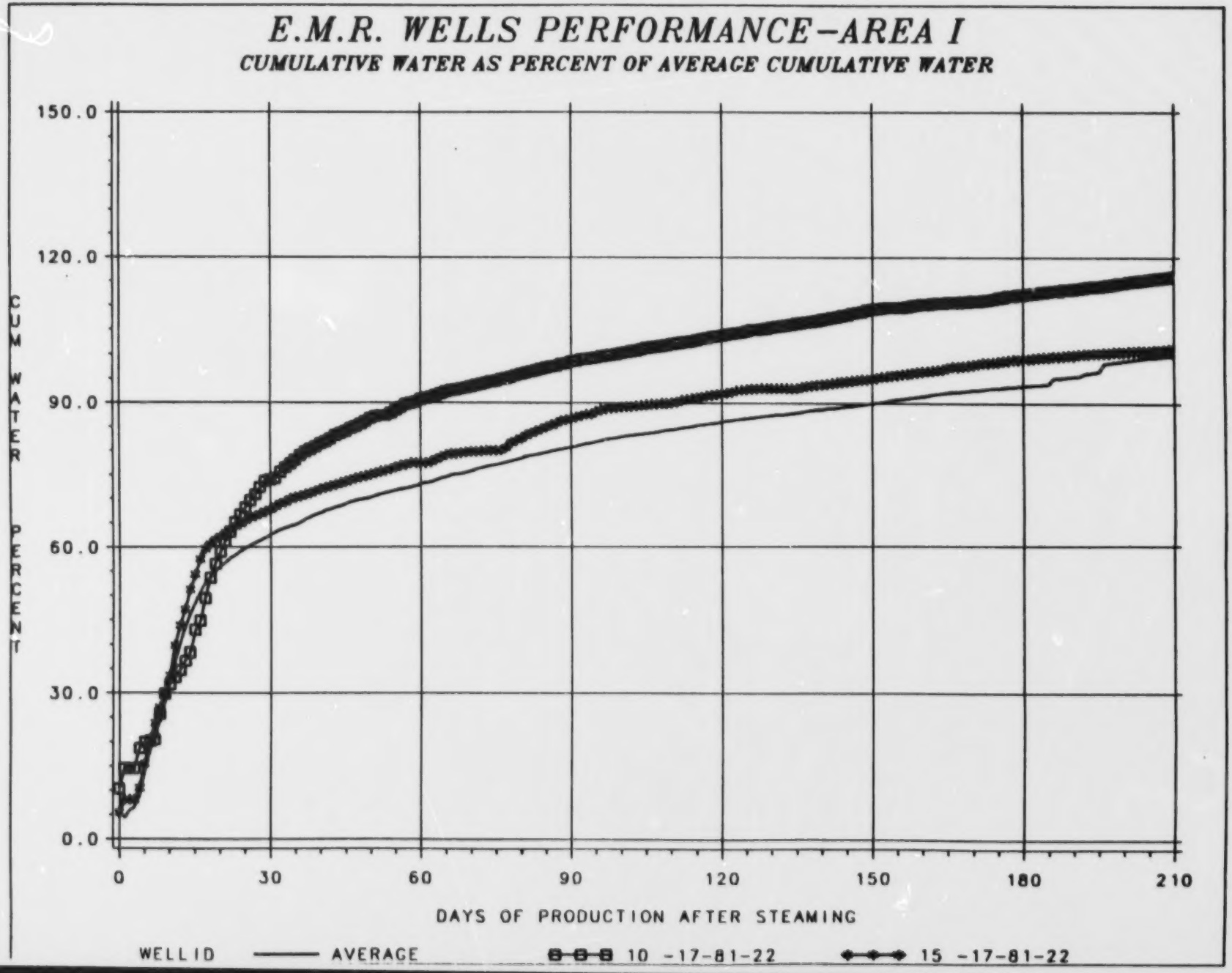

E.M.R. WELLS PERFORMANCE–AREA I
CUMULATIVE WATER AS PERCENT OF AVERAGE CUMULATIVE WATER
150.0
120.0
90.0
60.0
30.0
0.0
CUM WATER PERCENT
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
WELL ID
AVERAGE
10 -17-81-22
15 -17-81-22

FIGURE 89

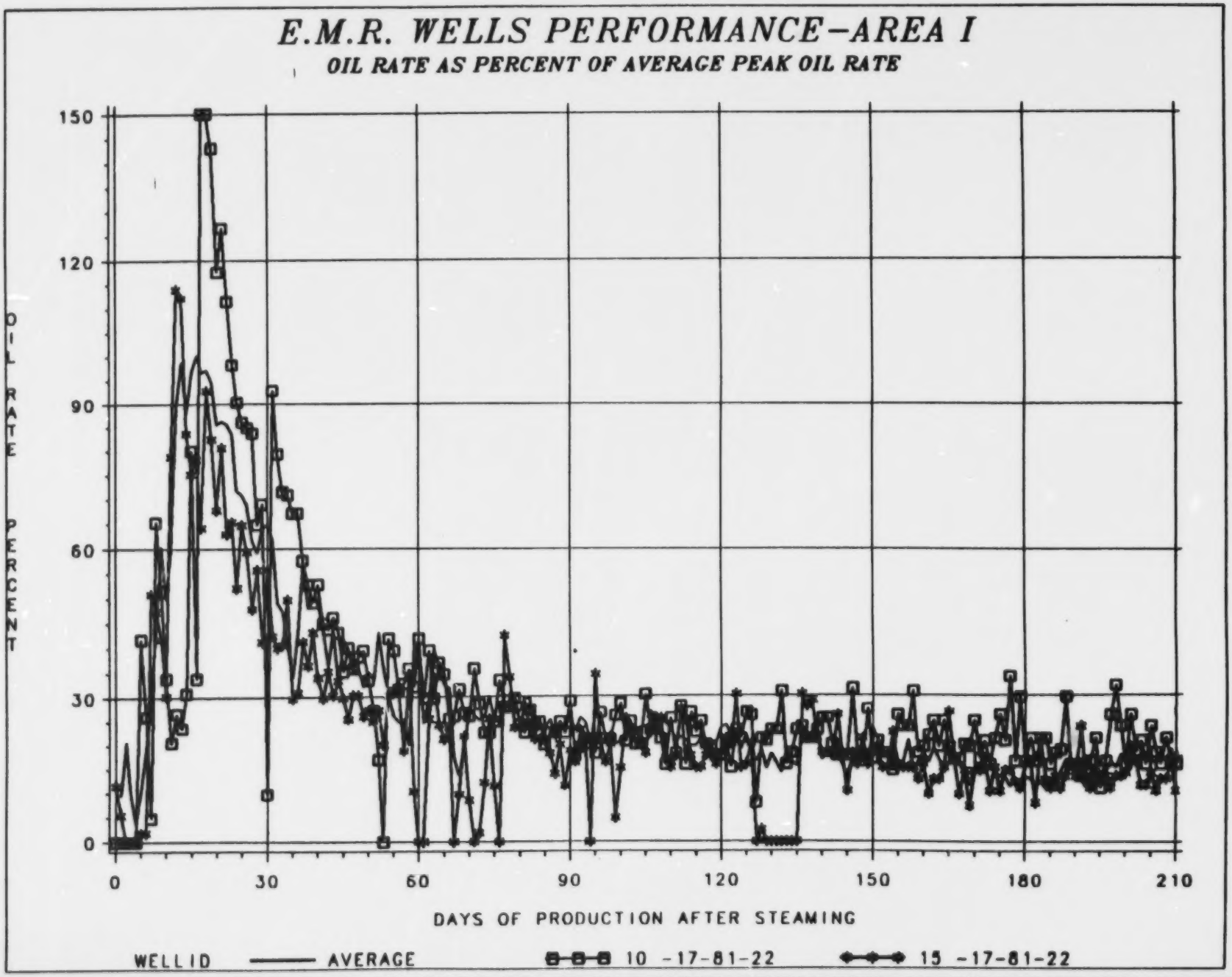

E.M.R. WELLS PERFORMANCE–AREA I
OIL RATE AS PERCENT OF AVERAGE PEAK OIL RATE
OIL RATE PERCENT
150
120
90
60
30
0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
WELL ID
AVERAGE
10 -17-81-22
15 -17-81-22

FIGURE 90

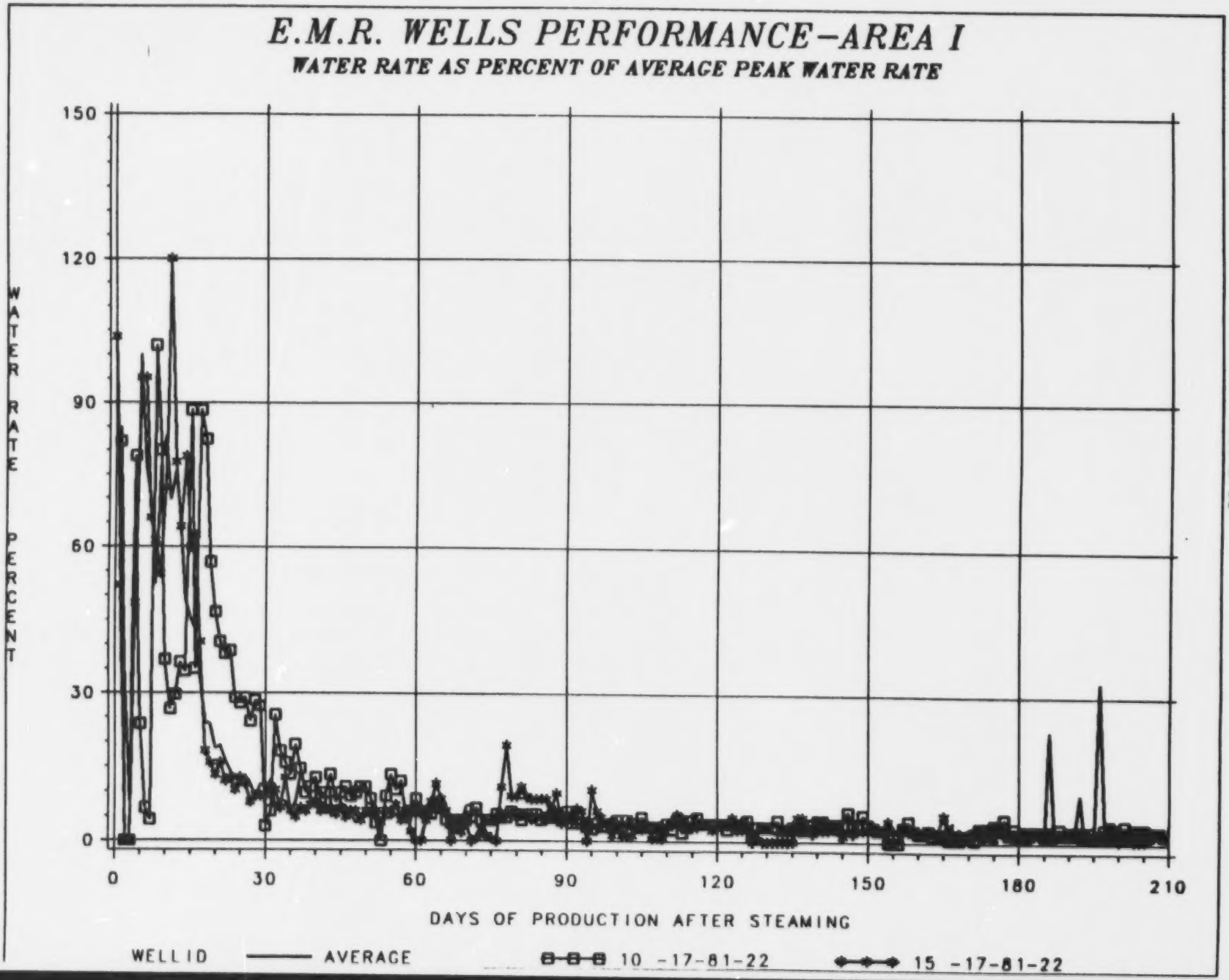

E.M.R. WELLS PERFORMANCE–AREA I
WATER RATE AS PERCENT OF AVERAGE PEAK WATER RATE
WATER RATE PERCENT
150
120
90
60
30
0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
WELL ID
AVERAGE
10 -17-81-22
15 -17-81-22

FIGURE 91

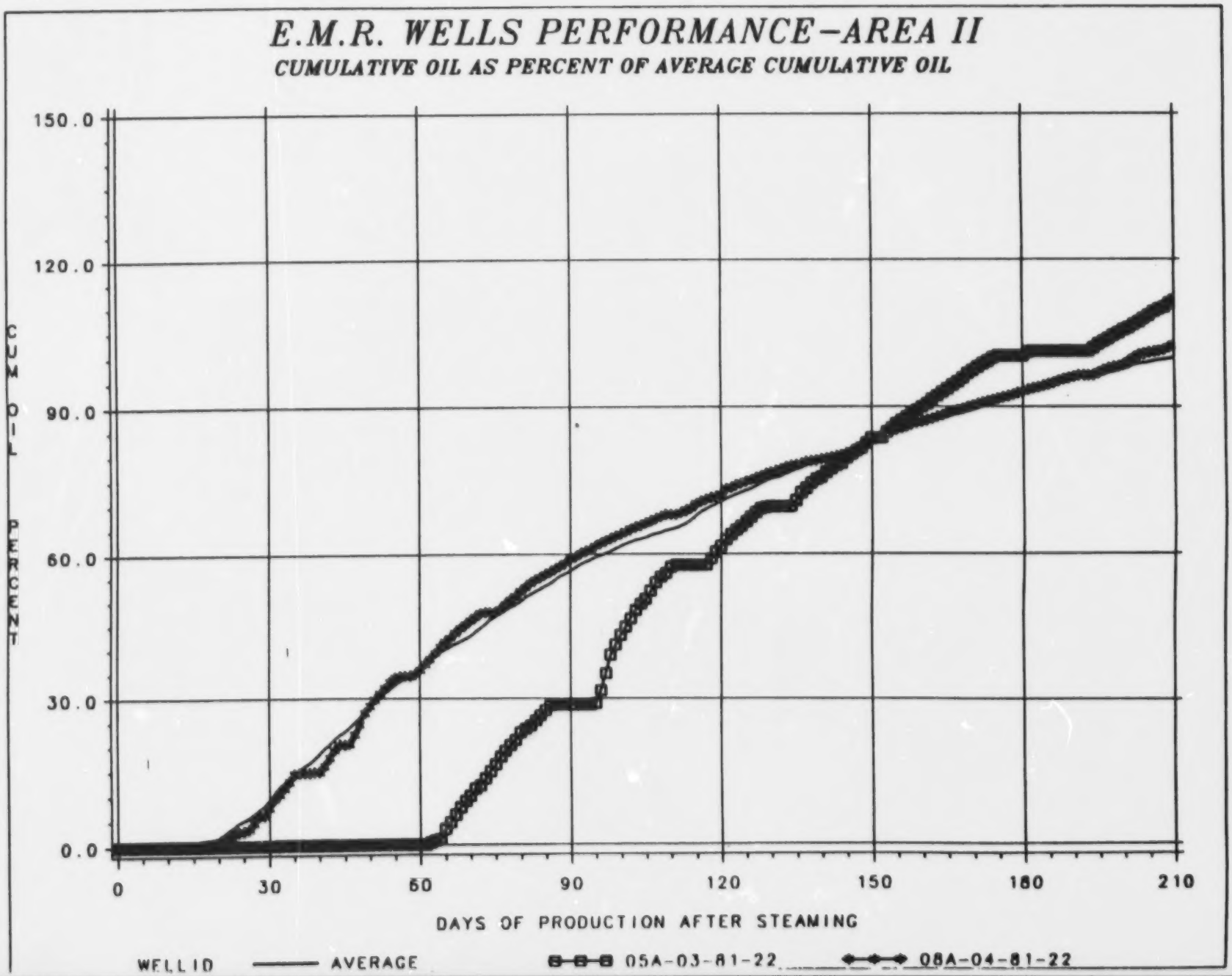

E.M.R. WELLS PERFORMANCE–AREA II
CUMULATIVE OIL AS PERCENT OF AVERAGE CUMULATIVE OIL
150.0
120.0
90.0
60.0
30.0
0.0
CUM OIL PERCENT
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
WELL ID
AVERAGE
05A-03-81-22
08A-04-81-22

FIGURE 92

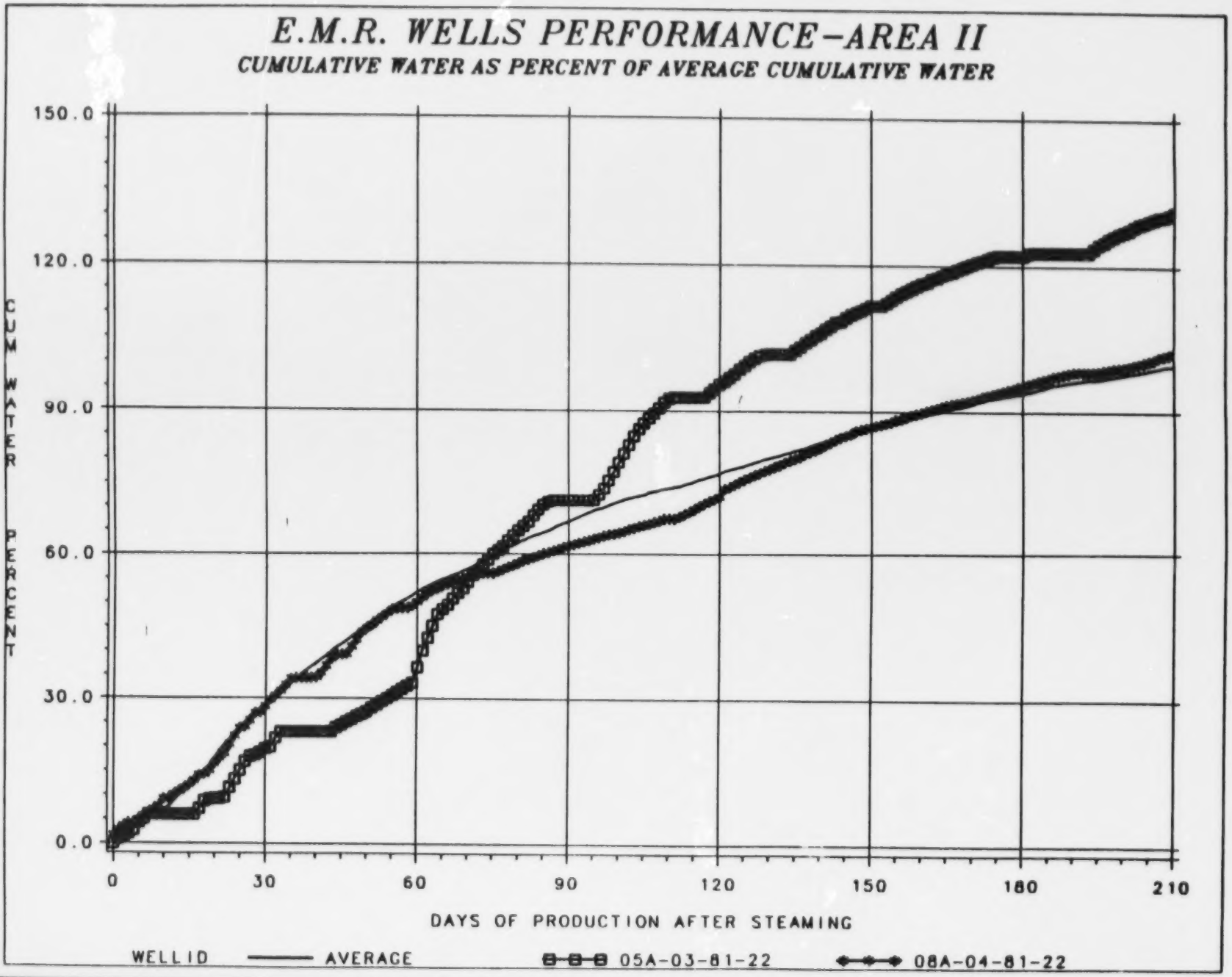

E.M.R. WELLS PERFORMANCE–AREA II
CUMULATIVE WATER AS PERCENT OF AVERAGE CUMULATIVE WATER
CUM WATER PERCENT
150.0
120.0
90.0
60.0
30.0
0.0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
WELL ID
AVERAGE
05A-03-81-22
08A-04-81-22

FIGURE 93

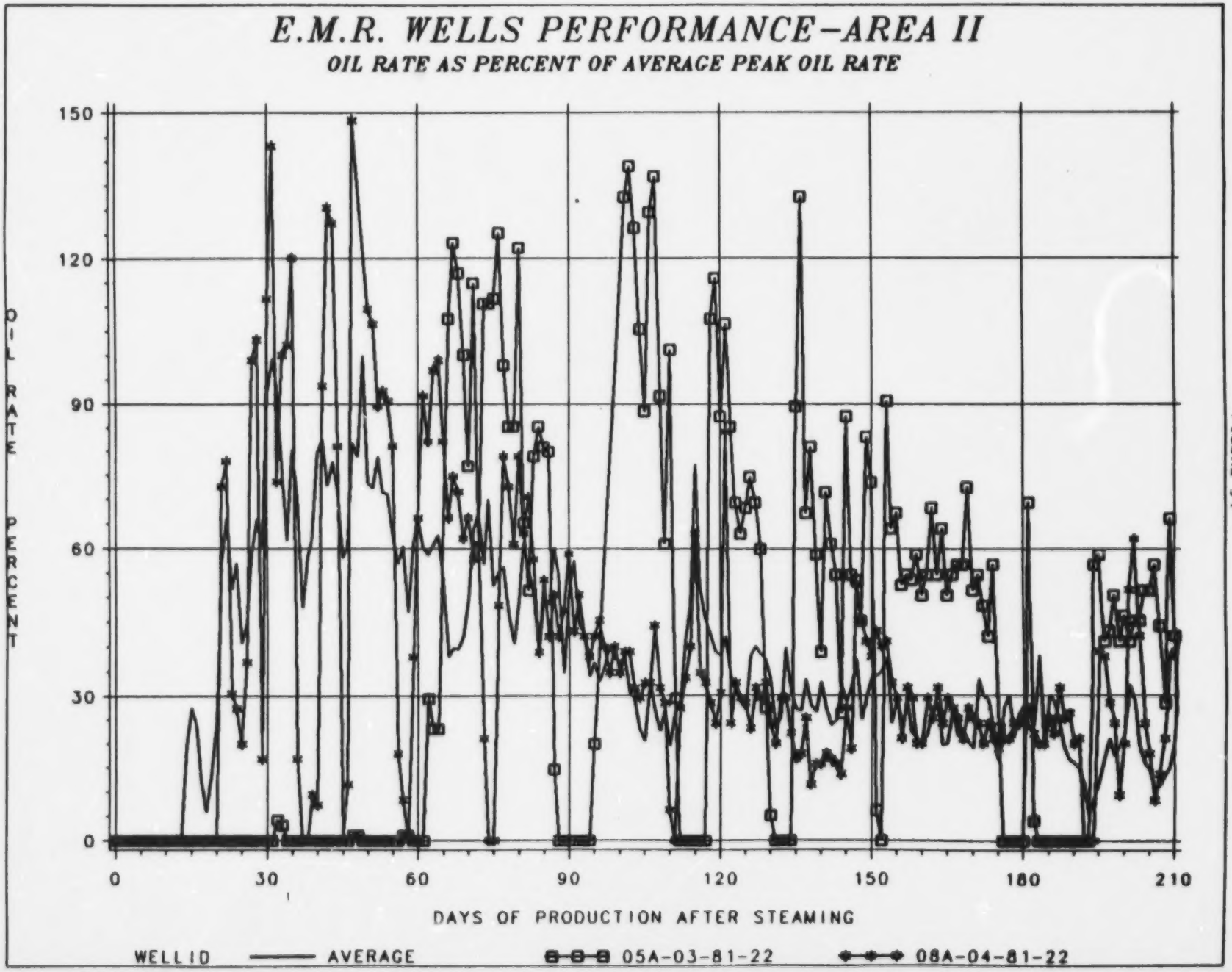

E.M.R. WELLS PERFORMANCE–AREA II
OIL RATE AS PERCENT OF AVERAGE PEAK OIL RATE
150
120
90
60
30
0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
WELL ID
AVERAGE
05A-03-81-22
08A-04-81-22

FIGURE 94

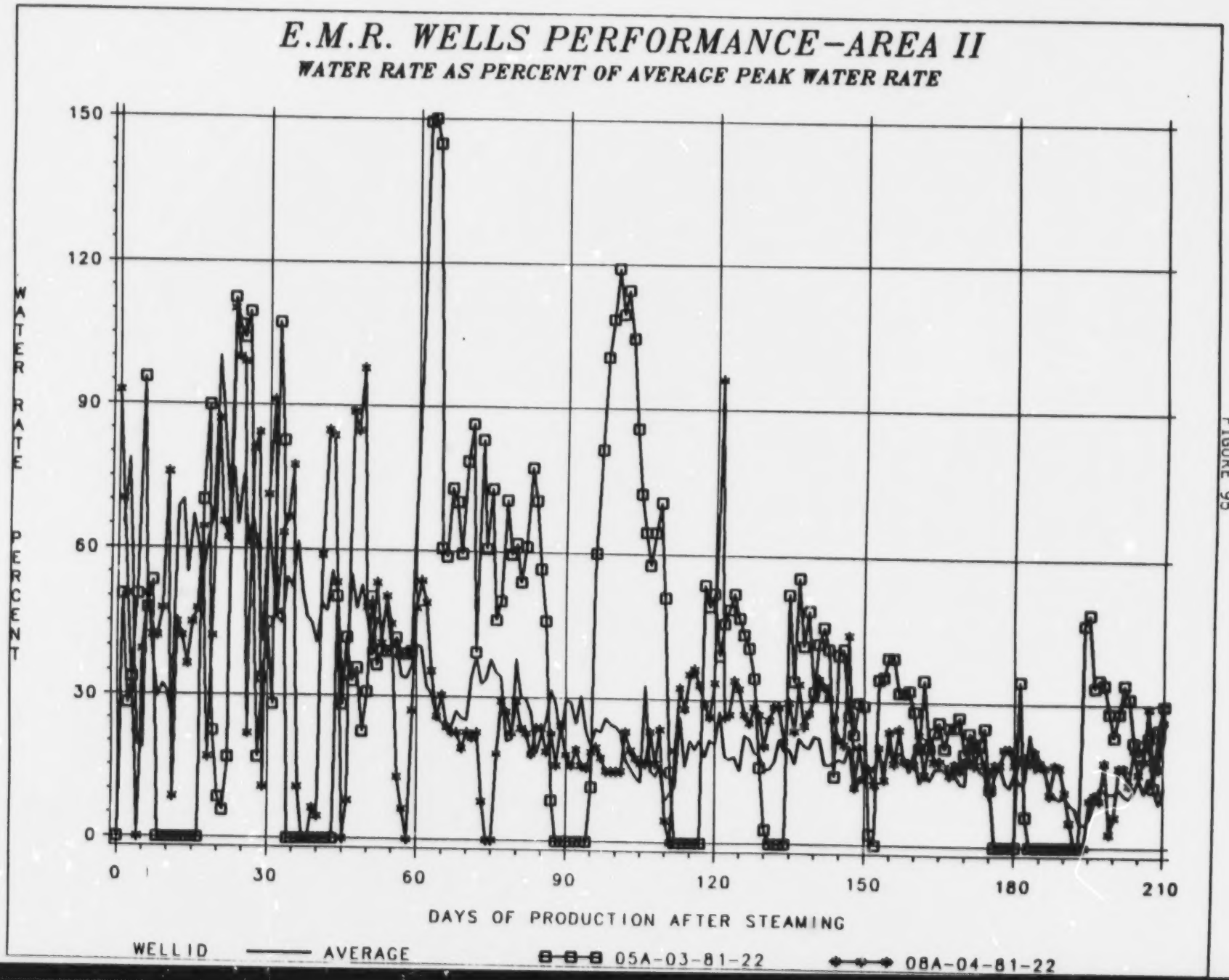

E.M.R. WELLS PERFORMANCE-AREA II
WATER RATE AS PERCENT OF AVERAGE PEAK WATER RATE
WATER RATE PERCENT
150
120
90
60
30
0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
WELL ID
AVERAGE
05A-03-81-22
08A-04-81-22

FIGURE 95

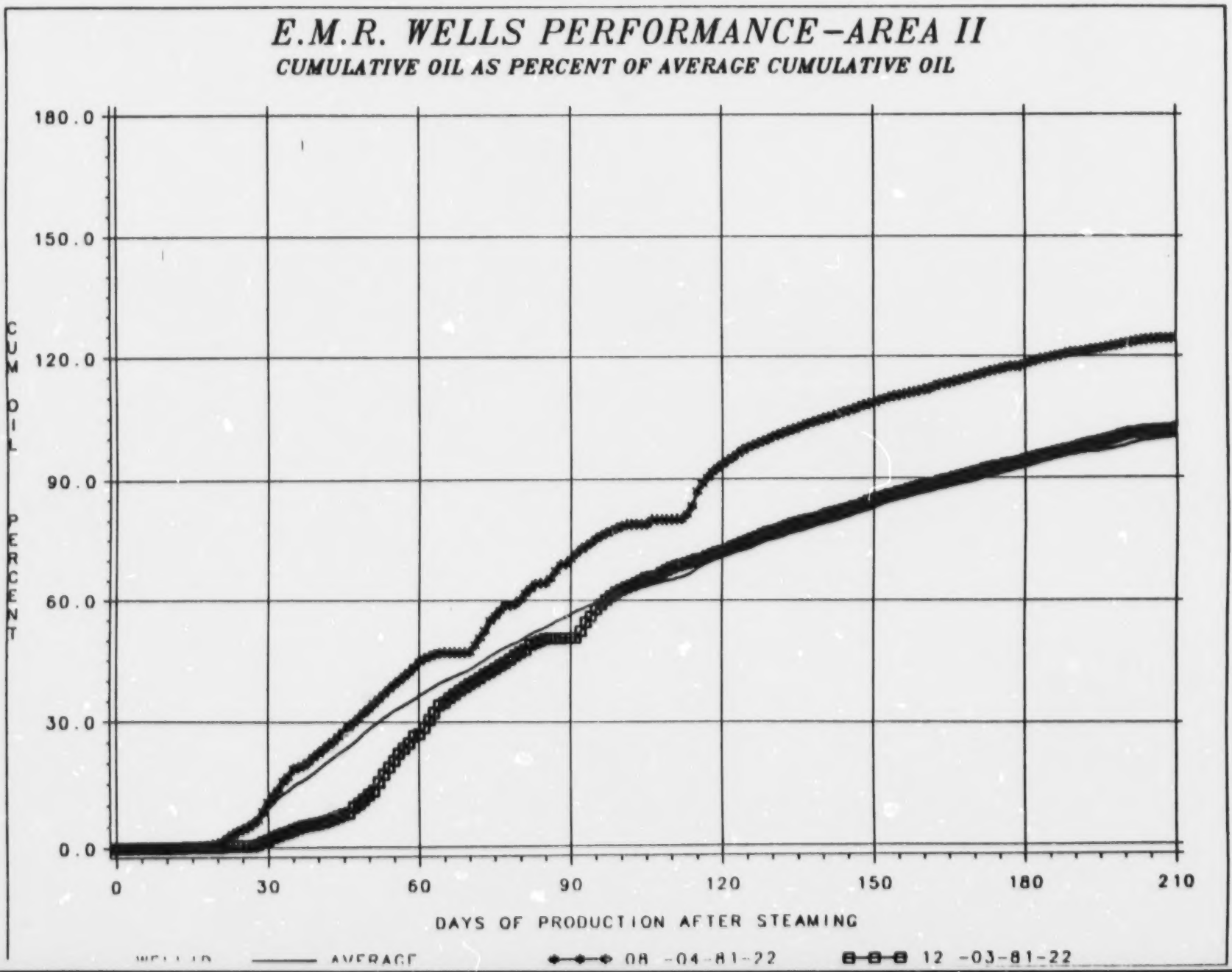

E.M.R. WELLS PERFORMANCE–AREA II
CUMULATIVE OIL AS PERCENT OF AVERAGE CUMULATIVE OIL
CUM O-F PERCENT
180.0
150.0
120.0
90.0
60.0
30.0
0.0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
WELL ID
AVERAGE
08 -04-81-22
12 -03-81-22

FIGURE 96

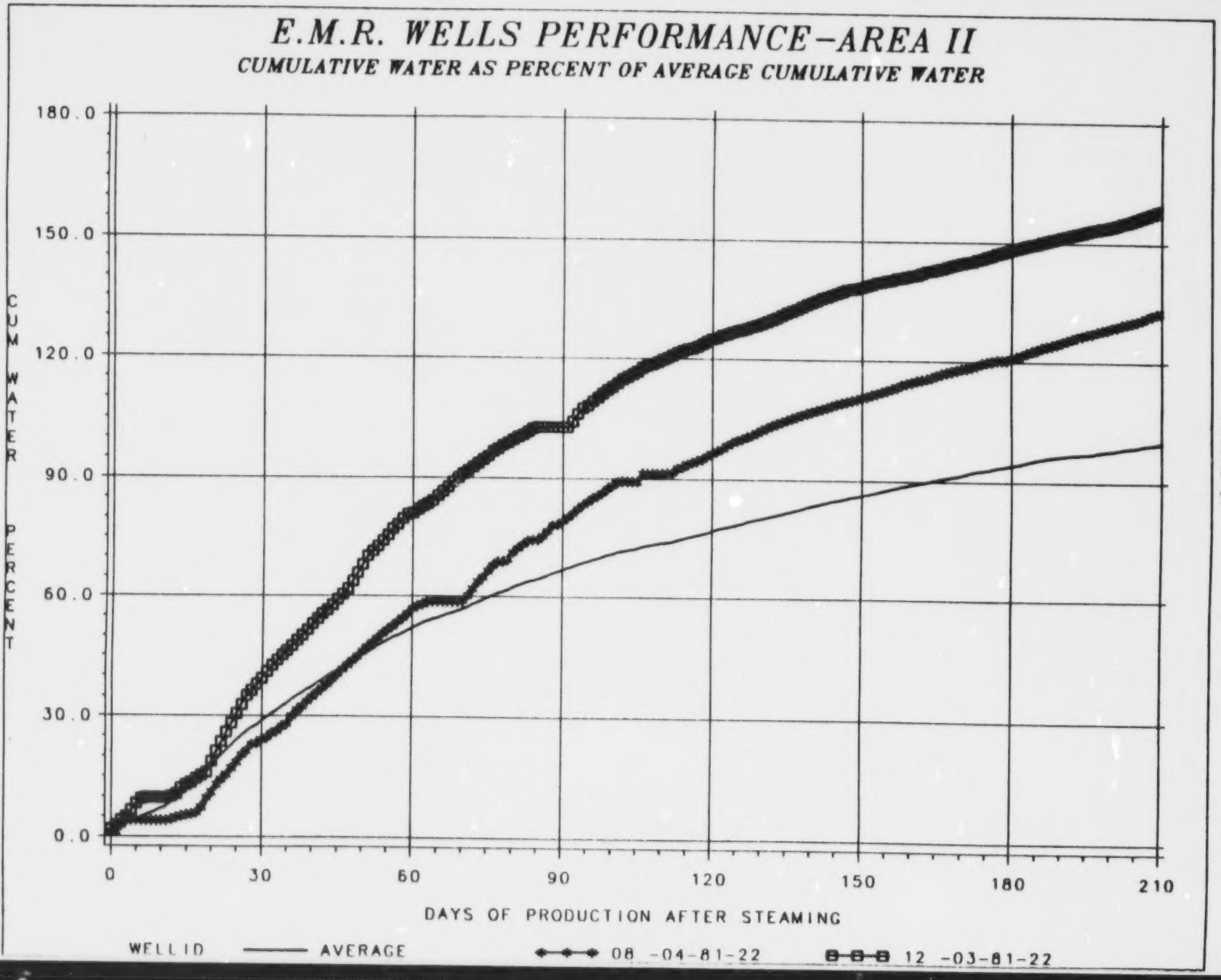

E.M.R. WELLS PERFORMANCE–AREA II
CUMULATIVE WATER AS PERCENT OF AVERAGE CUMULATIVE WATER
CUM WATER PERCENT
180.0
150.0
120.0
90.0
60.0
30.0
0.0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
WELL ID
AVERAGE
08 -04-81-22
12 -03-81-22

FIGURE 97

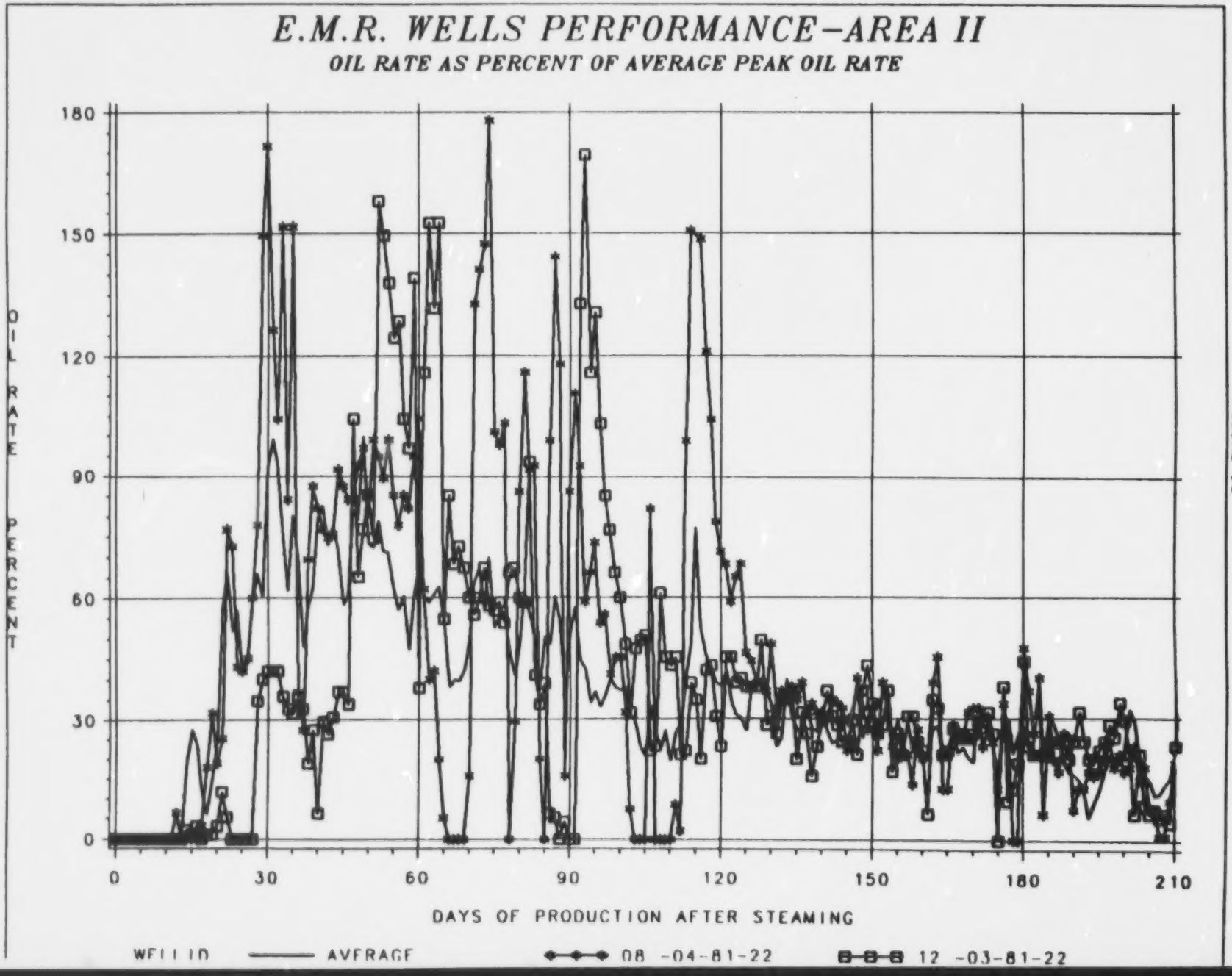

E.M.R. WELLS PERFORMANCE–AREA II
OIL RATE AS PERCENT OF AVERAGE PEAK OIL RATE
O-I RATE PERCENT
180
150
120
90
60
30
0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
WELL ID
AVERAGE
08 -04-81-22
12 -03-81-22

FIGURE 98

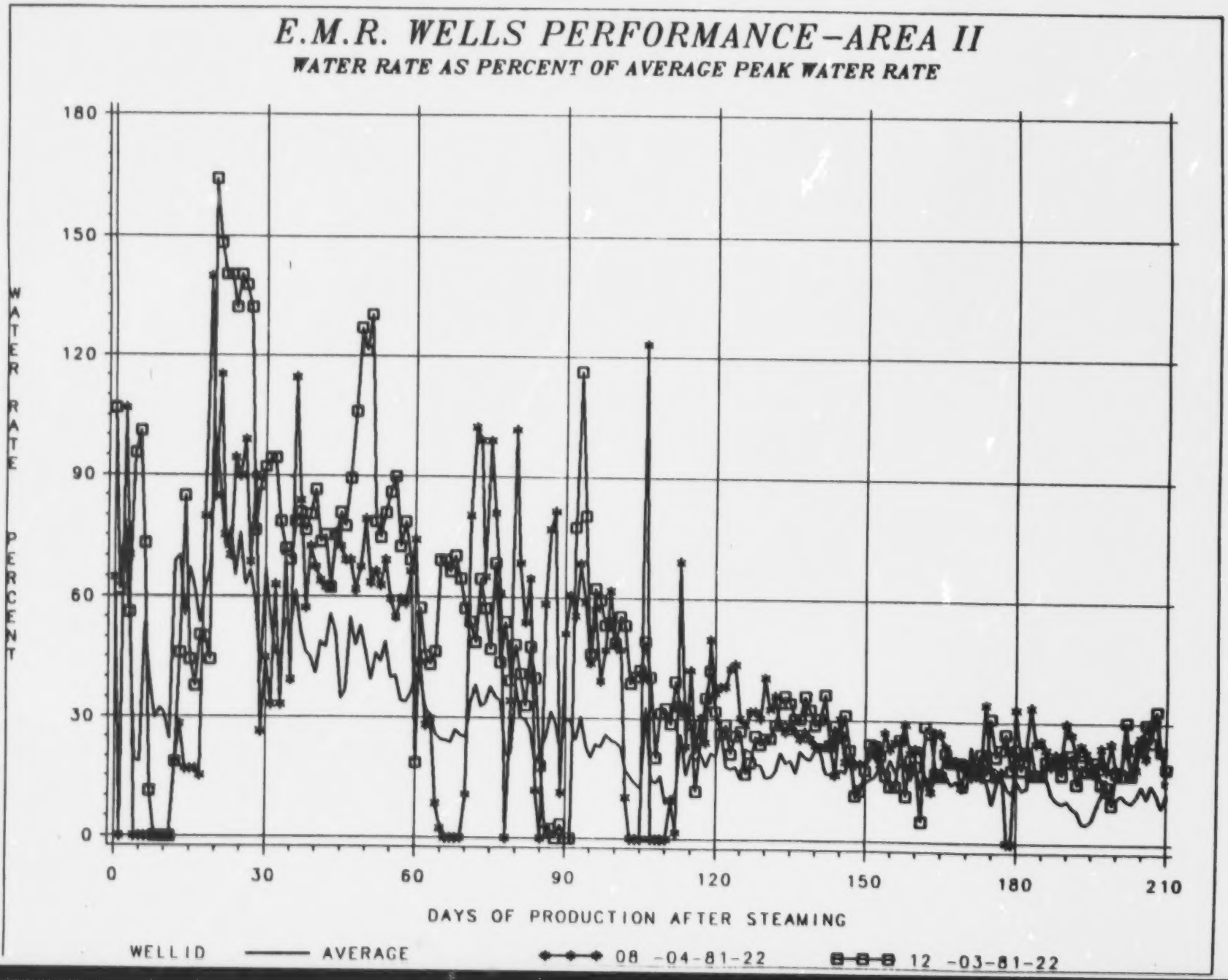

E.M.R. WELLS PERFORMANCE–AREA II
WATER RATE AS PERCENT OF AVERAGE PEAK WATER RATE
WATER RATE PERCENT
180
150
120
90
60
30
0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING
WELL ID
AVERAGE
08 -04-81-22
12 -03-81-22

FIGURE 99

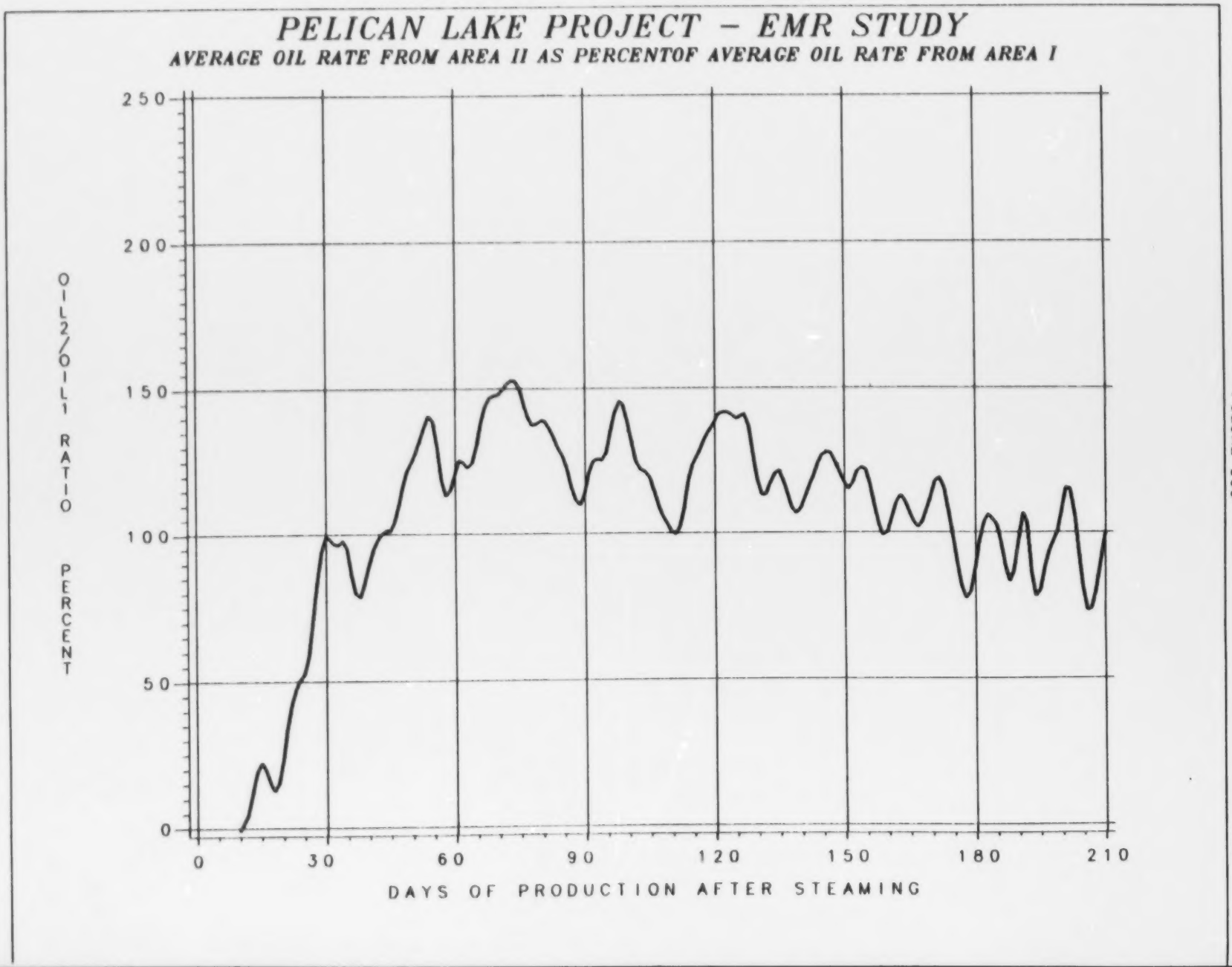

PELICAN LAKE PROJECT – EMR STUDY
AVERAGE OIL RATE FROM AREA II AS PERCENTOF AVERAGE OIL RATE FROM AREA I
OIL2/OIL1 RATIO PERCENT
250
200
150
100
50
0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING

FIGURE 100

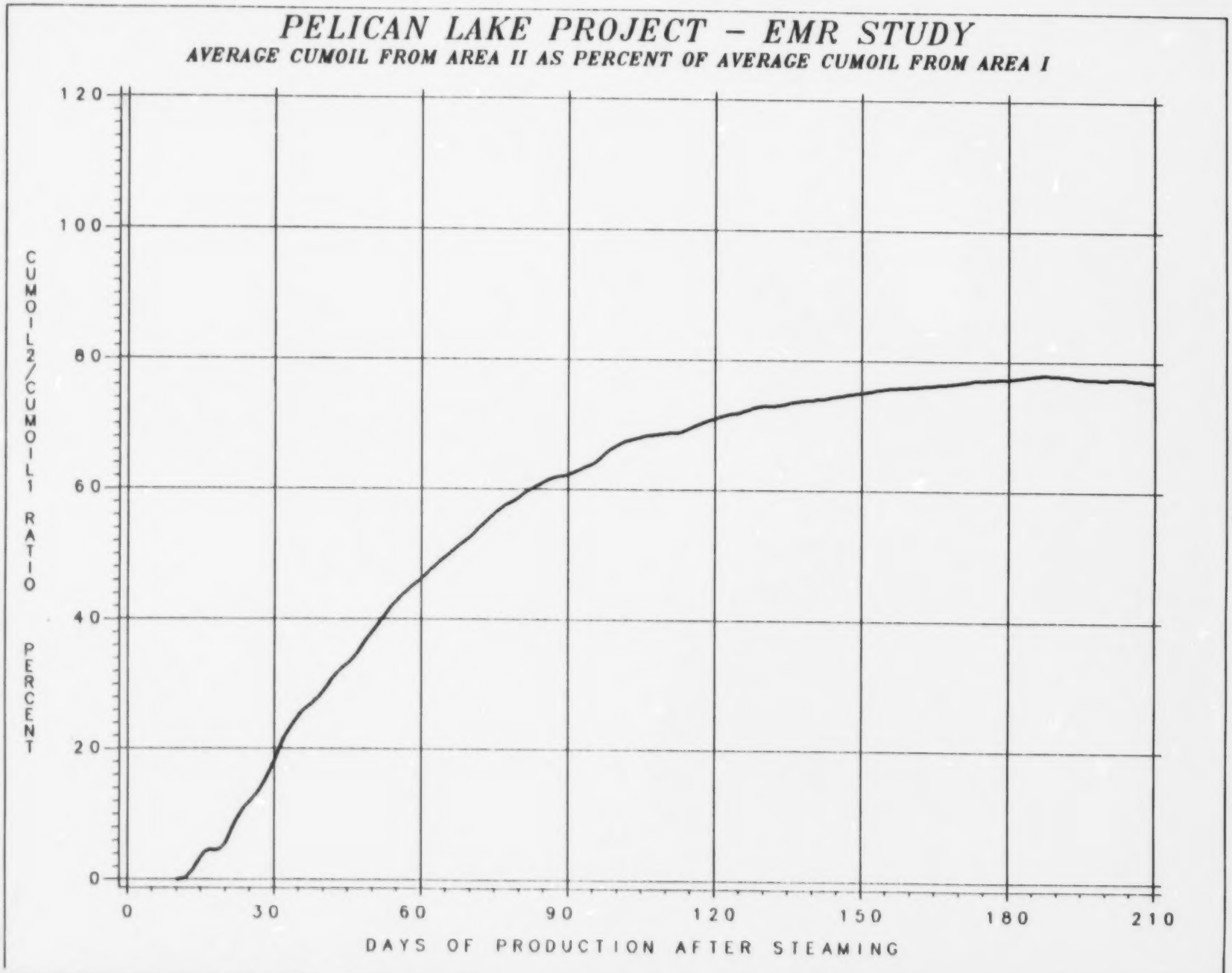

PELICAN LAKE PROJECT – EMR STUDY
AVERAGE CUMOIL FROM AREA II AS PERCENT OF AVERAGE CUMOIL FROM AREA I
CUMOIL2/CUMOIL1 RATIO PERCENT
120
100
80
60
40
20
0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING

FIGURE 101

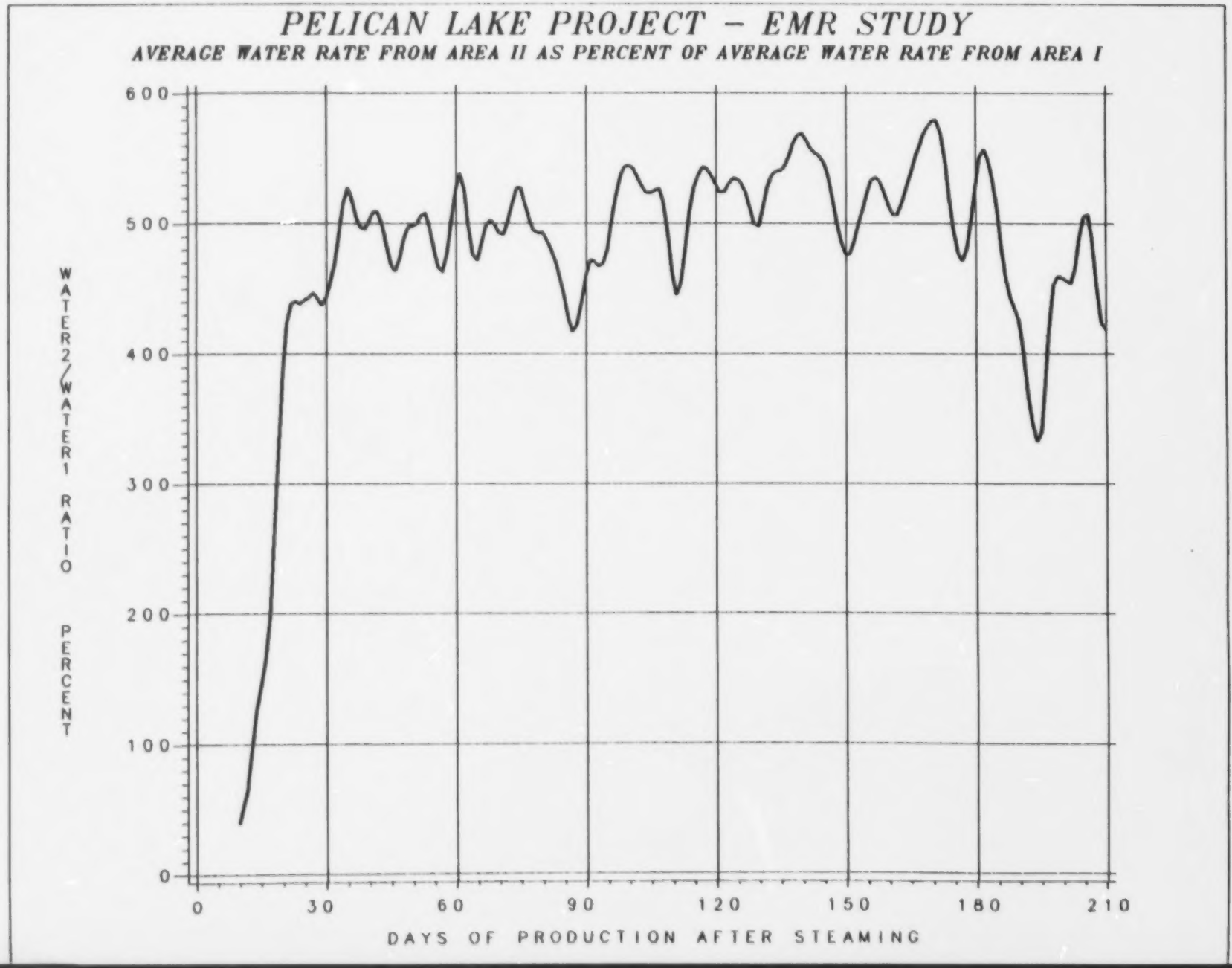

PELICAN LAKE PROJECT – EMR STUDY
AVERAGE WATER RATE FROM AREA II AS PERCENT OF AVERAGE WATER RATE FROM AREA I
WATER2/WATER1 RATIO PERCENT
600
500
400
300
200
100
0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING

FIGURE 102

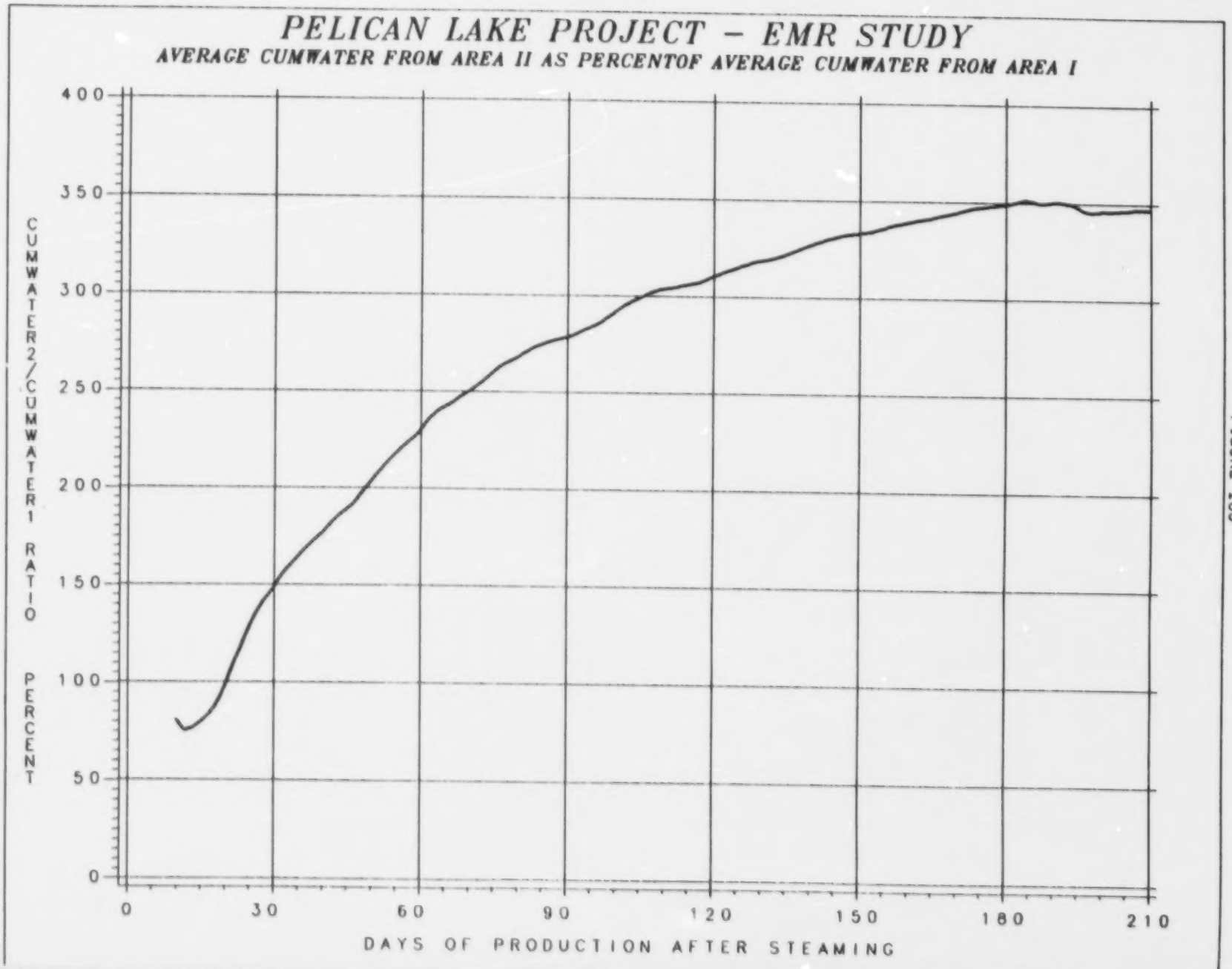
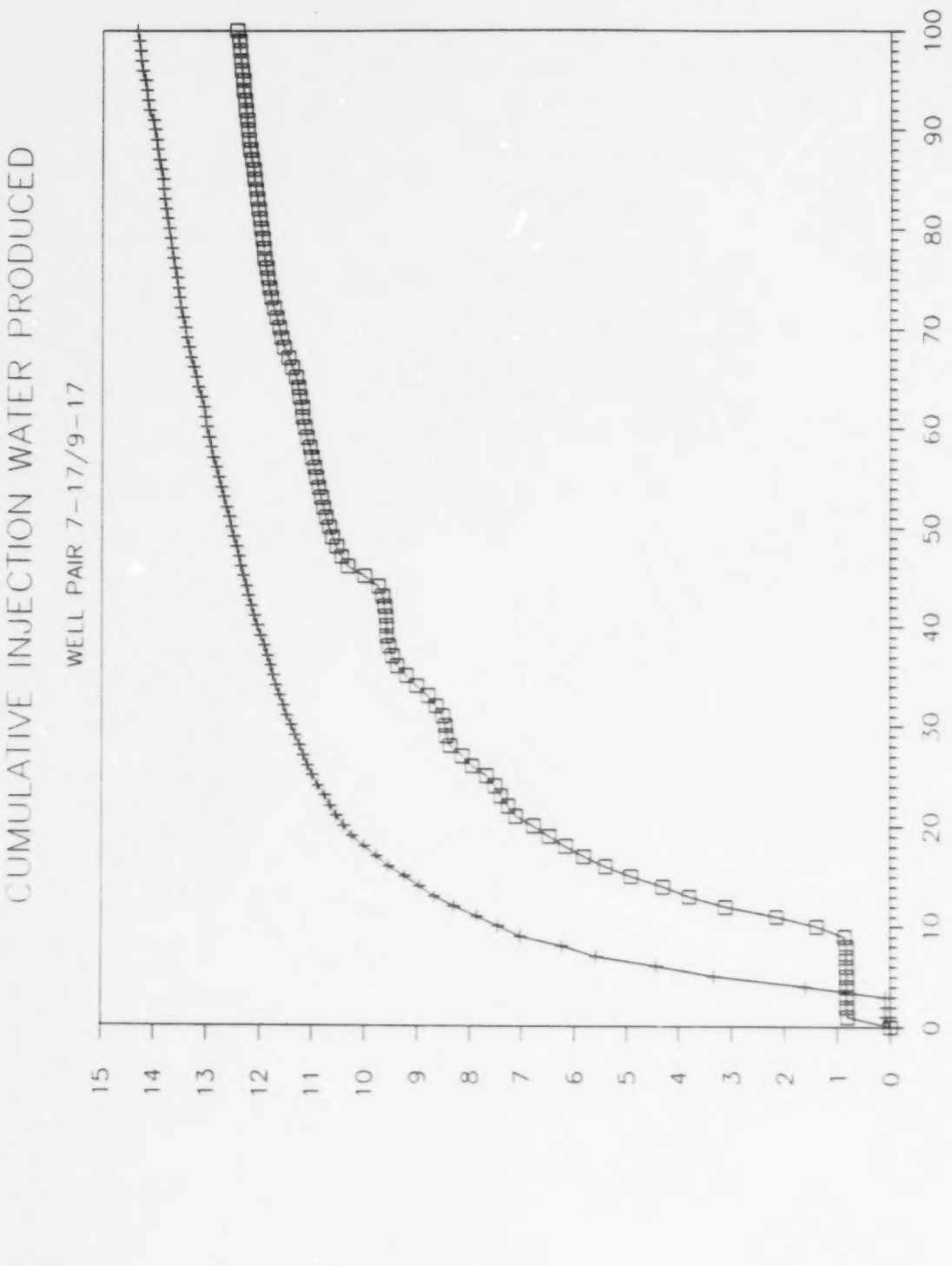

PELICAN LAKE PROJECT – EMR STUDY
AVERAGE CUMWATER FROM AREA II AS PERCENTOF AVERAGE CUMWATER FROM AREA I
CUMWATER2/CUMWATER1 RATIO PERCENT
400
350
300
250
200
150
100
50
0
0
30
60
90
120
150
180
210
DAYS OF PRODUCTION AFTER STEAMING

FIGURE 103

FIGURE 104


CUMULATIVE INJECTION WATER PRODUCED
WELL PAIR 7-17/9-17
INJECTED WATER RECOVERED(% OF INJECTED)
DAYS ON PRODUCTION
□ 07-17-081-22 W4M
+ 09-17-081-22 W4M
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
0
10
20
30
40
50
60
70
80
90
100

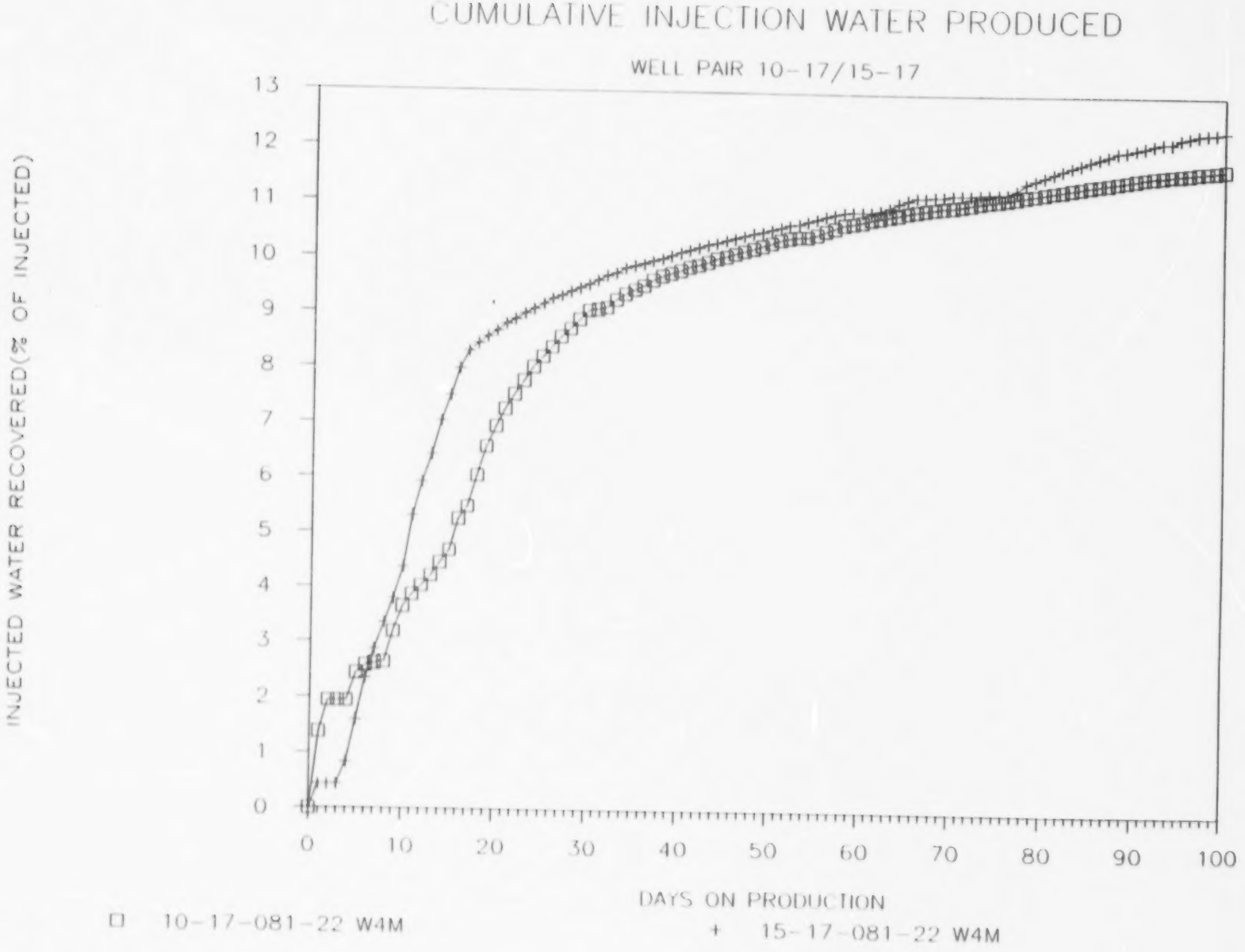

CUMULATIVE INJECTION WATER PRODUCED
WELL PAIR 10-17/15-17
INJECTED WATER RECOVERED(% OF INJECTED)
0
1
2
3
4
5
6
7
8
9
10
11
12
13
0
10
20
30
40
50
60
70
80
90
100
DAYS ON PRODUCTION
□ 10-17-081-22 W4M
+ 15-17-081-22 W4M

FIGURE 105

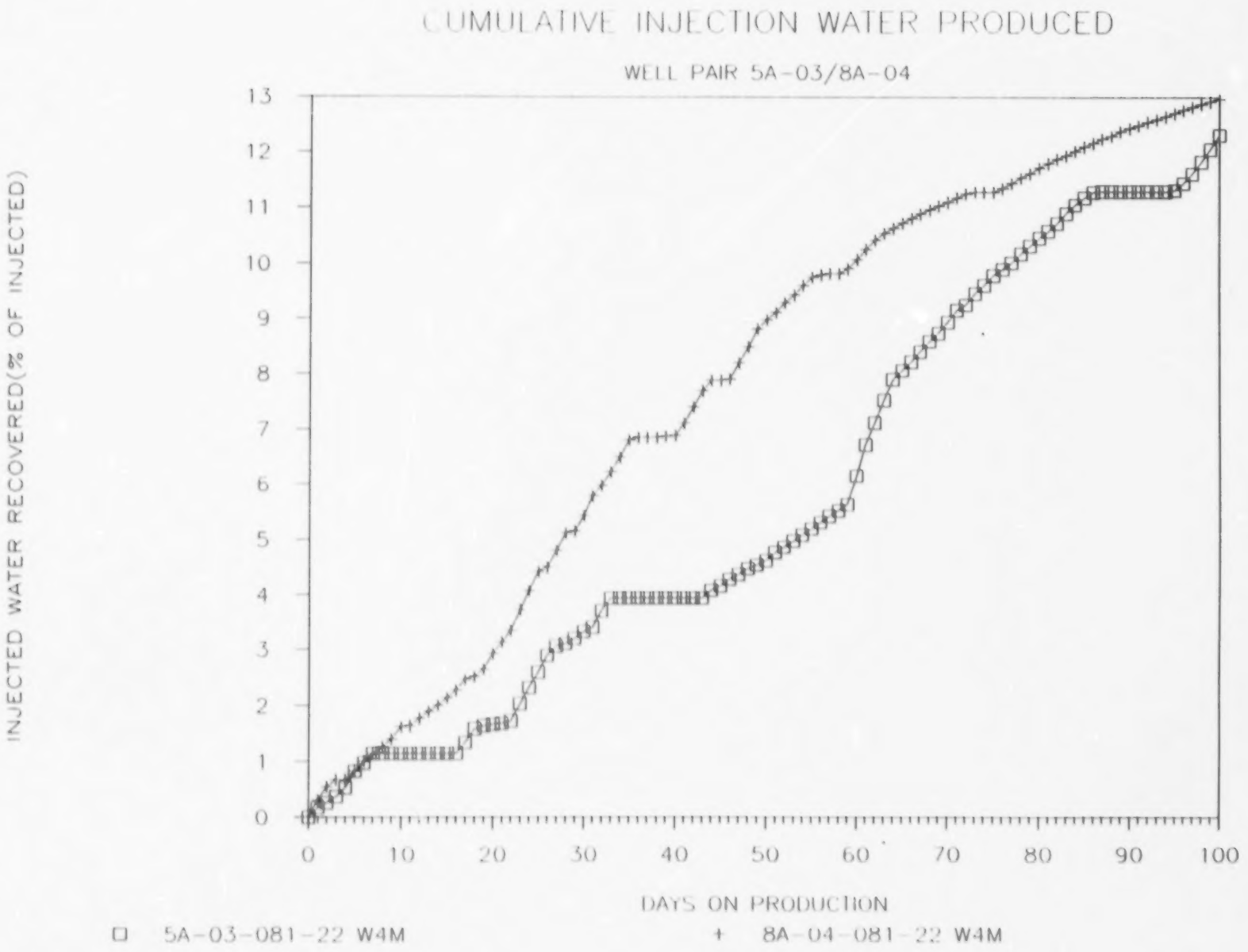

CUMULATIVE INJECTION WATER PRODUCED
WELL PAIR 5A-03/8A-04
INJECTED WATER RECOVERED(% OF INJECTED)
0
1
2
3
4
5
6
7
8
9
10
11
12
13
0
10
20
30
40
50
60
70
80
90
100
DAYS ON PRODUCTION
□ 5A-03-081-22 W4M
+ 8A-04-081-22 W4M

FIGURE 106

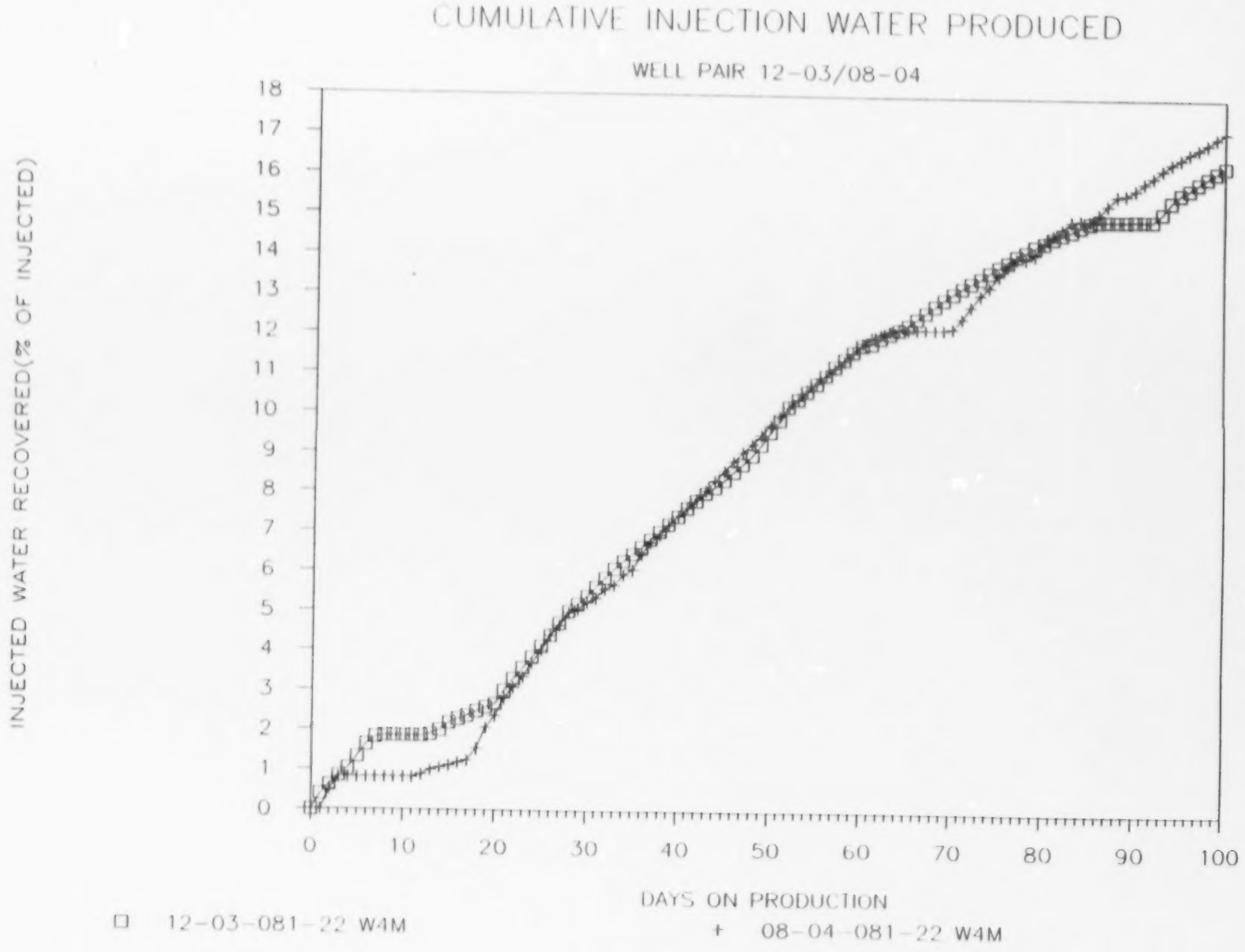
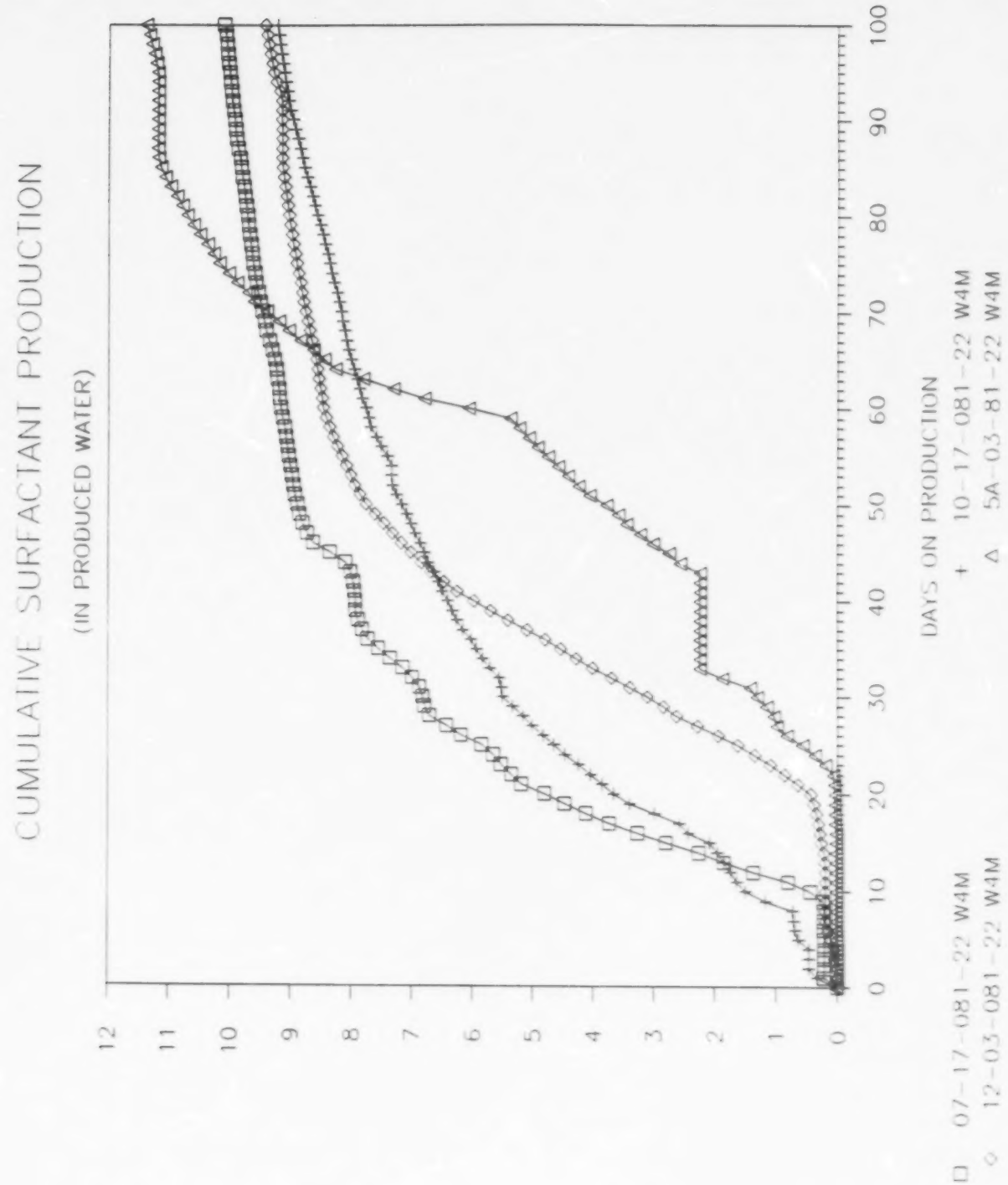

CUMULATIVE INJECTION WATER PRODUCED
WELL PAIR 12-03/08-04
INJECTED WATER RECOVERED(% OF INJECTED)
18
17
16
15
14
13
12
11
10
9
8
7
6
5
4
3
2
1
0
0
10
20
30
40
50
60
70
80
90
100
DAYS ON PRODUCTION
□ 12-03-081-22 W4M
+ 08-04-081-22 W4M

FIGURE 107

FIGURE 108


CUMULAIVE SURFACTANT PRODUCTION
(IN PRODUCED WATER)
SURFACTANT PRODUCTION (% OF INJECTED)
DAYS ON PRODUCTION
0
10
20
30
40
50
60
70
80
90
100
0
1
2
3
4
5
6
7
8
9
10
11
12
□ 07-17-081-22 W4M
◇ 12-03-081-22 W4M
+ 10-17-081-22 W4M
△ 5A-03-81-22 W4M

GULF PELICAN
RESERVOIR DESCRIPTION

GEOLOGICAL HORIZON	WABISKAW
TOP OF FORMATION	400 MKB
FORMATION THICKNESS:	3.5 – 6.5 M
FORMATION TEMPERATURE	22°
FORMATION PRESSURE	2375 KPA
AVERAGE PERMEABILITY	1000 MD – 3500 MD
AVERAGE POROSITY	29%
AVERAGE WATER SATURATION	30%
AVERAGE OIL SATURATION	70%
OIL VISCOSITY AT RESERVOIR TEMPERATURE	600 – 1200 MPAs
OIL GRAVITY AT RESERVOIR TEMPERATURE	973 KG/M³

TABLE 1

TABLE 2

COMPATABILITY OF STEAM ADDITIVES WITH

PELICAN LAKE RESERVOIR WATER AND BOILER CONDENSATE

ADDITIVE	RESERVOIR WATER		BOILER CONDENSATE	
	4°C	80°C	4°C	80°C
SUN TECH IV	No Precipitate	No Precipitate	No Precipitate	No Precipitate
SHELL LTS 18	No Precipitate	No Precipitate	No Precipitate	No Precipitate

TABLE 3

EFFECT OF STEAM ADDITIVES ON EMULSION BREAKS
OF PELICAN LAKE CRUDE AND RESERVOIR WATER, 80°C

TIME	RESERVOIR WATER/ CRUDE	SUNTECH IV-FA IN RESERVOIR WATER CRUDE	SHELL LTS 18 IN RESERVOIR WATER/ CRUDE
Minutes	% Break	% Break	% Break
1	20	25	30
2	75	50	60
4	95	90	90
6	98	100	100
8	100		

CONDITIONS 80 ml of centrifuged crude was blended with 20 ml reservoir water at 16000 RPM for 30 seconds. Water phase contained zero additive, 600 ppm Suntech IV-FA or 600 ppm Shell LTS 18

TABLE 4

EFFECT OF STEAM ADDITIVES ON EMULSION BREAKS
OF PELICAN LAKE CRUDE AND BOILER CONDENSATE, 80°C

TIME	BOILER CONDENSATE/ CRUDE	SUNTECH IV-FA IN BOILER CONDENSATE/ CRUDE	SHELL LTS 18 IN BOILER CONDENSATE/ CRUDE
Minutes	% Break	% Break	% Break
1	0	0	0
2	0	0	0
4	0	0	0
6	0	0	0
8	0	0	0
10	0	0	0
12	0	0	0
15	0	0	0
20	0	0	0
30	0	0	0
60	25	25	25
180	25	25	25

CONDITIONS 80 ml of centrifuged crude was blended with 20 ml boiler condensate at 16000 RPM for 30 seconds. The boiler condensate contained zero additive, 600 ppm Suntech IV-FA or 600 ppm Shell LTS 18

TABLE 5

INTERFACIAL TENSION OF PELICAN LAKE OIL
AT VARIOUS TEMPERATURES AFTER EQUILIBRATION

TEMP (°C)	DENSITY OIL (g/ml)	PRODUCED WATER (IFT mN/m)	PRODUCED WATER + LTS 18* (IFT mN/m)	BOILER CONDENSATE (IFT mN/m)
50	0.9442	13.06	0.12	0.25
75	0.9259	12.91	0.03	3.25
100	0.9877	11.24	0.05	5.04
125	0.8873	10.84	0.10	6.62
150	0.8699	9.13	0.21	13.15

* Shell ENORDET LTS 18 at a concentration of 5 g/l.

TABLE 6

EVOLUTION OF INTERFACIAL TENSION OF PELICAN LAKE CRUDE IN FORMATION WATER CONTAINING SHELL ENORDET LTS 18 AT 5g/l

RUN #1			RUN #2		RUN #3	
TIME (min)	TEMP (°C)	IFT (mN/m)	TIME (min)	IFT (mN/m)	TIME (min)	IFT (mN/m)
4	55.0	4.06	32	1.59	32	2.93
7	55.0	1.76	74	0.85	68	1.50
18	53.7	0.94	130	0.21	136	0.33
80	49.1	0.49	160	0.15	156	0.17
90	51.2		229	0.12	167	0.09
94	51.1				177	0.10
116	50.2	0.28			248	0.13
125	50.0	0.26				
157	49.2					
166	51.2					
247	50.4	0.15				
260	73.8	0.06	23	0.06	261	0.06
272	74.7	0.04	33	0.02	274	0.05
296	74.3	0.04	52	0.06	285	0.02
			69	0.03	306	0.02
304	105.4	0.04	86	0.03	330	0.03
311	104.0	0.06	94	0.04	336	0.04
331	105.0	0.07	99	0.04	343	0.04
341	104.5	0.08	105	0.05	348	0.04
369	128.3	0.14	116	0.08	365	0.08
280	127.6	0.16	139	0.10	453	0.11
390	128.0	0.17			458	0.11
395	128.3	0.16				
408	152.2	0.23	153	0.17	472	0.17
412	151.9		164	0.21	478	0.18
421	152.6	0.28			497	0.21
428	152.5	0.29			506	0.23
438	152.5	0.31			522	0.25
466	152.7	0.34			528	0.25

TABLE 7

INTERFACIAL TENSION VERSUS TEMPERATURE

PELICAN LAKE OIL IN PRODUCED WATER CONTAINING 5 g/l SURFACTANT

TEMP (C)	IFT (mN/m) LTS 18	IFT (mN/m) SUNTECH IV FA
50	0.12	0.09
75	0.03	0.14
100	0.05	0.22
125	0.10	0.37
150	0.21	0.54

TABLE 8

INTERFACIAL TENSION OF PELICAN LAKE OIL
IN PRODUCED WATER CONTAINING SUNTECH IV FA

CONC (g/L)	TEMP (°C)	TIME (min)	INTERFACIAL TENSION (mN/m)
0.05	50	1307	0.003
0.05	100	225	0.070
0.05	150	326	2.800
0.20	50	213	0.020
0.20	100	50	0.100
0.20	150	60	0.930
0.50	50	180	0.050
0.50	100	199	0.130
0.50	150	180	0.710
2.00	50	180	0.090
2.00	100	265	0.340
2.00	150	307	0.480
5.00	50	120	0.090
5.00	100	339	0.480
5.00	150	413	1.200

TABLE 9

PROPERTIES OF PELICAN LAKE CRUDE

(5A-3-81-22 W4M)

ACID NUMBER		4.03 mg KOH/ml
DENSITY g/ml	@ 25°C	0.9623
	50°C	0.9442
	75°C	0.9259

TABLE 10

VISCOSITY AND DENSITY TABLE

	VISCOSITY		DENSITY	
	Dynamic mPa.s @20°C	Kinematic mm^2s^{-1} @ 20°C	API Gravity	Relative Density @ 15°C
AREA I				
15-17	1239	1283	14.2	0.971
10-17	1213	1256	14.5	0.969
9-17	1127	1170	15.0	0.966
7-17	1177	1220	14.7	0.968
AREA II				
8-4	1471	1517	13.9	0.973
12-3	1072	1111	14.7	0.968
8A-4	1127	1167	14.5	0.969
5A-3	1257	1300	14.4	0.970

TABLE 11

ANALYSIS OF WATERS FROM PRIMARY PRODUCTION

Location	Ion Concentration (mg/l)															pH
	Ca	Mg	Fe	Mn	B	Sr	Na	Si	Al	K	Cl	SO4	HCO3	CO3	OH	
5A-03-81-22 W4M	4.50	6.50	0.15	0.006	5.59	0.49	1920.0	4.2	0.53	41.4	1287.0	29.1	2600.0	0	0	8.21
* 8A-04-81-22 W4M		6.30	0.19	0.009	3.66	0.75	1730.0	4.4	0.29	280.0	1735.0	27.0	1960.0	0	0	7.54

* Note: This water was contaminated with KCl from a workover and was not used for baseline.

TABLE 12

ANALYSIS OF SOURCE WATER

Location	Ion Concentration (mg/l)															pH
	Ca	Mg	Fe	Mn	B	Sr	Na	Si	Al	K	Cl	SO4	HCO3	CO3	OH	
08-04-81-22 W4M	0.5	0.18	0.09	<0.004	0.3	0.003	135.0	1.5	0.01	2.34	78.0	35.0	188.0	0	0	7.78
15-17-81-22 W4M	28.7	6.5	0.17	0.007	0.1	0.10	4.0	2.1	0.03	0.9	2.0	4.1	130.0	0	0	7.21

TABLE 13

BOILER CONDENSATE ANALYSIS

Location	Ion Concentration (mg/l)														pH
	Ca	Mg	Fe	Mn	B	Sr	Na	Si	Al	K	Cl	SO4	HCO3	CO3	OH	
AREA I																
15-17	0.1	0.12	0.84	0.009	0.02	0.002	305.0	10.6	0.64	6.5	27.7	109.0	0	0	0	11.40
10-17	0.1	0.1	0.29	<0.004	0.1	<0.001	370.0	14.6	0.71	3.8	21.0	121.0	0	135.0	122.0	11.25
9-17	0.2	<0.01	0.16	<0.004	0.02	0.002	208.0	8.8	0.34	0.6	7.0	64.1	0	99.6	67.5	11.19
7-17	0.4	0.27	0.98	0.023	0.03	0.002	520.0	14.3	1.0	7.8	304.0	101.0	253.0	209.0	0	9.90
AREA II																
8-4	0.2	0.04	0.08	<0.004	0.13	0.001	460.0	2.2	0.09	6.7	191.0	135.0	0	139.0	122.0	11.48
12-3	0.4	<0.01	0.08	<0.004	0.38	0.002	1310.0	5.4	0.10	11.9	395.0	414.0	0	389.0	367.0	11.74
8A-4	6.4	<0.01	0.18	<0.004	0.36	0.002	1030.0	8.9	0.34	11.2	550.0	290.0	0	180.0	297.0	11.93
5A-3	0.64	0.01	0.02	<0.004	0.4	0.002	664.0	5.2	0.07	7.7	280.0	210.0	0	184.0	166.0	11.38

TABLE 14

WATER ANALYSIS - WELL 07-17-81-22 W4M (ADDITIVE)

Date	Sample Description	Ion Concentration (mg/l)															Surf. Concen.
		Ca	Mg	Fe	Mn	B	Sr	Na	Si	Al	K	Cl	SO4	HCO3	CO3	OH	pH	(mg/l)
87-10-15	Produced Fluid (flowback)	1.5	1.40	5.20	0.04	10.7	0.020	308	125.0	1.80	8.3	269	111.0	265	0	0	8.19	189
87-10-16	Produced Fluid (flowback)	3.5	0.31	6.63	0.14	1.6	0.015	202	210.0	0.64	7.9	138	51.3	247	0	0	8.25	50
87-10-26	Produced Fluid (pumping)	3.2	0.28	0.34	0.02	11.1	0.067	528	93.2	0.38	89.7	453	119.0	706	0	0	8.30	278
87-11-01	Produced Fluid (pumping)	1.6	0.38	<0.10	<0.004	14.6	0.023	590	70.0	0.29	42.2	323	54.4	824	86.8	0	8.93	742
87-11-08	Produced Fluid (pumping)	2.6	0.20	<0.10	<0.004	15.9	0.035	610	50.0	0.19	37.1	352	55.7	1010	48.2	0	8.39	743
87-11-12	Produced Fluid (pumping)	0.8	0.42	<0.10	<0.004	17.0	0.025	655	50.9	0.21	38.3	365	46.0	1150	0	0	7.41	821
87-11-18	Produced Fluid (pumping)	1.1	0.70	0.09	0.013	18.9	0.051	730	41.9	0.46	37.5	348	54.6	1188	0	0	7.24	632
87-11-29	Produced Fluid (pumping)	2.4	0.80	0.22	0.007	17.9	0.130	770	36.3	0.41	47.6	456	54.8	1197	0	0	7.95	634
87-12-08	Produced Fluid (pumping)	2.1	0.60	0.92	0.004	16.7	0.049	620	27.1	2.84	40.0	305	51.0	1006	0	0	8.08	369
87-12-29	Produced Fluid (pumping)	2.2	0.60	0.46	0.016	15.6	0.060	715	24.6	0.62	88.5	367	76.8	1196	32.2	0	8.34	424
88-01-12	Produced Fluid (pumping)	20.8	1.20	0.26	0.032	15.6	0.140	650	21.5	0.44	70.2	414	48.6	1040	24.1	0	8.39	539
88-02-09	Produced Fluid (pumping)	0.7	<0.10	0.14	0.019	17.4	0.034	743	19.7	0.10	47.3	390	32.3	1188	0	0	8.30	493

TABLE 15

WATER ANALYSIS - WELL 09-17-81-22 W4M (NON-ADDITIVE)

Date	Sample Description	Ion Concentration (mg/l)																Surf. Concen.
		Ca	Mg	Fe	Mn	B	Sr	Na	Si	Al	K	Cl	SO4	HCO3	CO3	OH	pH	(mg/l)
87-09-13	Produced Fluid (Flowback)	2.6	0.33	2.00	0.240	9.9	0.015	259	200.0	1.53	18.9	116	87.9	422	0	0	7.95	
87-09-18	Produced Fluid (Pumping)	0.4	0.28	0.37	0.016	13.8	0.007	267	118.0	0.81	15.2	118	63.2	515	0	0	7.81	
87-09-30	Produced Fluid (pumping)	1.1	0.69	0.13	0.009	21.9	0.020	468	57.9	0.38	27.0	207	46.7	834	0	0	6.97	
87-10-08	Produced Fluid (pumping)	1.5	0.80	0.23	<0.004	24.9	0.030	525	42.9	0.99	25.2	253	82.3	932	0	0	6.97	
87-10-23	Produced Fluid (pumping)	1.5	0.87	0.49	<0.001	26.2	0.029	550	32.2	1.55	26.8	214	61.7	883	0	0	7.90	
87-11-13	Produced Fluid (pumping)	3.0	1.40	0.31	0.007	21.8	0.055	550	21.7	0.98	25.3	297	62.6	1015	28.1	0	8.33	<10
87-11-20	Produced Fluid (pumping)	1.2	0.70	0.36	<0.004	23.2	0.028	625	23.5	1.43	32.0	285	52.6	1079	0	0	7.49	<10
87-12-18	Produced Fluid (pumping)	2.9	1.00	0.80	<0.004	19.0	0.076	577	19.1	2.71	88.0	401	65.6	888	0	0	7.78	<10

TABLE 16

WATER ANALYSIS WELL - 10-17-81-22 W4M (ADDITIVE)

Date	Sample Description	Ion Concentration (mg/l)															pH	Surf. Concen. (mg/l)
		Ca	Mg	Fe	Mn	B	Sr	Na	Si	Al	K	Cl	SO4	HCO3	C03	OH		
87-09-15	KCl Preflush	124.0	28.8	0.78	0.390	0.5	0.95	177	7.4	0.03	7310	6810	433	553	0	0	8.21	
87-09-29	Produced Fluid (flowback)	4.9	0.6	0.14	0.018	7.9	0.02	265	230.0	2.20	20.6	205	88	170	0	0	6.86	156
87-09-30	Produced Fluid (flowback)	1.0	0.5	<0.01	0.005	1.5	<0.01	202	33.2	0.31	16.4	206	78	317	0	0	7.03	162
*87-10-04	Produced Fluid (pumping)	28.0	3.2	12.50	0.210	9.0	0.25	393	122.0	0.28	928.0	1380	214	175	0	0	7.01	223
87-10-07	Produced Fluid (pumping)	5.1	0.7	0.33	0.016	14.6	0.04	337	160.0	0.88	63.8	436	142	120	0	0	7.36	414
87-10-12	Produced Fluid (pumping)	4.2	0.9	<0.01	<0.004	18.3	0.07	319	106.0	0.62	33.5	264	125	230	0	0	6.68	306
87-10-17	Produced Fluid (pumping)	1.5	0.4	0.25	<0.004	23.1	0.03	380	60.5	0.90	32.1	284	56	540	0	0	8.14	475
87-10-19	Produced Fluid (pumping)	7.4	1.0	0.14	0.016	25.1	0.14	365	50.6	0.44	31.0	238	55	493	0	0	7.54	397
87-10-23	Produced Fluid (pumping)	1.6	0.4	0.04	<0.004	21.8	0.02	353	35.8	0.22	25.3	276	33	440	0	0	7.08	604
*87-10-30	Produced Fluid (pumping)	58.0	9.5	0.15	0.33	9.5	0.87	717	20.5	0.30	1527.0	2560	203	317	0	0	6.63	565
87-11-08	Produced Fluid (pumping	3.5	1.1	1.10	<0.004	21.9	0.10	500	32.7	3.30	60.4	508	48	532	0	0	7.97	698
*87-11-22	Produced Fluid (pumping)	9.2	1.3	0.42	0.040	19.2	0.31	763	25.4	1.08	473.0	1350	101	293	0	0	7.59	714
87-12-06	Produced Fluid (pumping)	4.1	0.7	1.10	<0.004	19.6	0.12	500	23.3	3.68	91.1	482	106	664	0	0	8.15	695
87-12-27	Produced Fluid (pumping)	0.3	0.7	0.67	0.013	24.0	0.02	595	25.4	2.37	99.0	473	73	697	0	0	7.97	791
88-01-10	Produced Fluid (pumping)	15.3	1.9	4.13	0.065	21.5	0.09	522	18.5	1.33	90.0	418	59	688	0	0	7.92	652

* Samples contaminated with KCl workover fluid

TABLE 17

WATER ANALYSIS WELL - 15-17-81-22 W4M (NON-ADDITIVE)

Date	Sample Description	Ion Concentration (mg/l)															pH	Surf. Concen. (mg/l)
		Ca	Mg	Fe	Mn	B	Sr	Na	Si	Al	K	Cl	SO4	HCO3	CO3	OH		
87-08-11	KCl Preflush	4.5	6.5	0.15	0.006	5.69	0.49	1920	4.0	0.53	47.4	1287	29.1	2600	0	0	8.21	
87-08-27	Produced Fluid (Flowback)	0.3	0.2	2.60	0.350	9.8	0.006	205	217.0	1.44	16.0	142	24.7	270	0	0	8.08	<10
87-09-01	Produced Fluid (pumping)	0.6	0.1	0.31	0.048	12.6	<0.01	248	142.0	0.95	32.6	196	35.8	388	0	0	7.20	
87-09-03	Produced Fluid (pumping)	4.4	0.7	0.33	0.030	13.5	0.016	290	125.0	0.90	26.4	187	44.0	383	0	0	7.68	<10
87-09-08	Produced Fluid (pumping)	0.2	<0.1	0.30	0.006	12.7	0.010	315	67.6	0.99	30.3	208	40.8	398	0	0	8.09	<10
87-09-14	Produced Fluid (pumping)	0.2	<0.1	0.43	0.011	16.9	0.006	310	47.0	1.56	40.9	208	62.6	392	0	0	8.11	<10
87-09-22	Produced Fluid (pumping)	0.5	<0.1	1.20	0.016	20.0	0.016	420	42.3	3.05	40.1	223	62.4	620	0	0	8.07	<10
87-09-30	Produced Fluid (pumping)	0.3	0.1	0.48	0.017	20.6	0.014	457	36.2	1.86	42.6	275	68.7	613	0	0	7.70	<10
87-10-14	Produced Fluid (pumping)	0.3	<0.1	0.79	<0.004	18.4	0.011	407	30.6	2.80	49.2	255	65.6	590	0	0	7.93	<10
*87-10-30	Produced Fluid (pumping)	0.5	0.2	0.16	<0.004	16.0	0.026	662	22.4	0.45	480.0	1310	95.6	515	0	0	8.23	<10
*87-11-13	Produced Fluid (pumping)	3.2	1.2	0.75	0.029	14.9	0.067	390	17.5	1.56	150.0	407	117.0	539	0	0	8.06	<10
87-12-18	Produced Fluid (pumping)	0.7	<0.1	0.32	0.041	14.8	0.014	430	15.0	0.59	85.4	323	66.3	638	20.5	0	8.35	<10

* Samples contaminated with KCl workover fluid

TABLE 18

WATER ANALYSIS - WELL 05A-03-81-22 W4M (ADDITIVE)

Date	Sample Description	Ion Concentration (mg/l)															Surf. Concen.
		Ca	Mg	Fe	Mn	B	Sr	Na	Si	Al	K	Cl	SO4	HCO3	CO3	OH	pH	(mg/l)
88-01-03	Produced Fluid (flowback)	3.15	0.26	6.13	0.015	5.2	0.030	373	185.0	1.30	24.7	380	199.0	144	0	0	7.17	<10
88-01-05	Produced Fluid (flowback)	2.50	0.22	5.47	0.014	5.5	0.030	390	194.0	1.20 *	24.6	404	204.0	112	0	0	8.00	
88-01-07	Produced Fluid (flowback)	1.33	0.02	0.38	0.015	10.1	0.020	420	184.0	1.10	27.6	398	235.0	149	0	0	7.08	9
88-01-20	Produced Fluid (pumping)	6.24	0.11	8.07	0.250	15.4	0.077	588	200.0	0.50	66.9	536	426.0	235	0	0	7.48	10
*88-01-25	Produced Fluid (pumping)	9.05	0.06	2.42	0.093	15.8	0.098	552	164.0	0.50	238	615	427.0	249	0	0	7.56	227
88-01-30	Produced Fluid (pumping)	5.30	0.26	6.85	0.150	19.3	0.064	544	167.0	0.37	34.6	502	417.0	163	0	0	7.46	318
88-02-19	Produced Fluid (pumping)	3.13	0.07	1.58	0.056	22.9	0.066	620	140.0	0.30	35.8	511	306.0	429	0	0	7.77	650
88-02-25	Produced Fluid (pumping)	3.01	0.10	1.08	0.045	24.5	0.070	664	132.0	0.23	37.6	497	259.0	664	0	0	7.70	
88-02-29	Produced Fluid (pumping)	3.22	0.23	0.73	0.038	24.4	0.083	660	127.0	0.22	37.8	495	182.0	775	0	0	8.04	595
88-03-03	Produced Fluid (pumping)																	426
88-03-07	Produced Fluid (pumping)	4.70	0.46	0.08	0.015	30.6	0.092	620	76.7	0.24	42.2	500	156.0	755	38.6	0	8.54	
88-03-21	Produced Fluid (pumping)	3.80	0.35	0.26	0.021	30.0	0.160	720	56.7	0.55	49.6	584	67.6	761	96.5	0	8.87	235
*88-04-04	Produced Fluid (pumping)	11.70	2.90	1.42	0.210	29.5	0.47	806	39.0	0.27	322.0	861	74.2	1230	0	0	7.29	180
88-04-18	Produced Fluid (pumping)	5.40	2.40	0.18	0.019	23.0	0.39	967	26.2	0.50	54.0	706	39.0	1226	0	0	8.26	40
88-05-07	Produced Fluid (pumping)	8.60	3.50	0.04	0.022	22.5	0.55	980	20.3	0.05	38.0	691	35.0	1246	0	0	8.20	40
88-05-21	Produced Fluid (pumping)	690	2.10	0.17	0.031	28.0	0.31	970	30.0	0.30	137.0	835	51.7	1094	65.1	0	8.35	40

* Samples contaminated with KCl workover fluid

TABLE 19

WATER ANALYSIS - WELL 08A-04-81-22 W4M (NON-ADDITIVE)

Date	Sample Description	Ion Concentration (mg/l)																Surf. Concen.
		Ca	Mg	Fe	Mn	B	Sr	Na	Si	Al	K	Cl	SO4	HCO3	CO3	OH	pH	(mg/l)
87-11-23	Produced Fluid (flowback)	3.25	0.80	2.60	0.650	2.2	0.028	270	126.0	0.29	22.6	350	84.0	113	0	0	7.65	
87-11-24	Produced Fluid (flowback)	5.14	0.25	1.23	0.270	3.7	0.027	225	124.0	0.99	21.5	313	86.0	56	0	0	7.48	<10
87-11-30	Produced Fluid (pumping)	6.0	0.07	0.52	0.038	13.9	0.033	480	161.0	0.57	67.0	665	149.0	137	0	0	7.90	
87-12-07	Produced Fluid (pumping)	7.1	0.15	0.65	0.048	18.9	0.032	502	163.0	0.48	49.6	670	169.0	152	0	0	7.71	
87-12-14	Produced Fluid (pumping)	6.1	0.18	1.10	0.023	18.2	0.039	426	146.0	0.49	103.0	582	139.0	206	0	0	7.70	
87-12-22	Produced Fluid (pumping)	6.8	0.30	0.54	0.098	17.9	0.063	430	98.2	0.32	36.9	459	59.1	444	0	0	8.05	
87-12-28	Produced Fluid (pumping)	3.8	0.78	0.44	0.009	21.2	0.077	485	69.2	1.07	48.5	438	63.0	466	0	0	7.82	<10
88-01-09	Produced Fluid (pumping)	2.9	0.77	0.82	0.014	25.9	0.087	640	56.0	1.45	66.0	580	66.6	858	0	0	7.45	
88-01-30	Produced Fluid (pumping)	2.6	0.61	0.45	0.008	22.8	0.102	600	33.3	1.14	55.7	569	44.6	834	0	0	8.10	
88-02-20	Produced Fluid (pumping)	1.2	0.10	0.43	<0.004	21.6	0.082	740	30.0	1.11	43.9	548	36.2	1005	0	0	8.22	<10
88-02-27	Produced Fluid (pumping)	2.9	0.83	1.28	0.007	22.7	0.112	700	35.1	3.50	47.0	603	42.0	1050	0	0	7.71	

TABLE 20

WATER ANALYSIS - WELL 12-03-81-22 W4M (ADDITIVE)

Date	Sample Description	Ion Concentration (mg/l)															Surf. Concen.
		Ca	Mg	Fe	Mn	B	Sr	Na	Si	Al	K	Cl	SO4	HCO3	CO3	OH	pH	(mg/l)
88-02-04	Produced Fluid (flowback)	2.6	0.58	0.49	0.033	0.96	0.009	114	78.2	0.84	4.5	42	53.1	194	0	0	7.78	9
88-02-06	Produced Fluid (flowback)	2.5	0.37	0.05	0.068	3.40	0.016	290	133.0	0.67	18.9	289	147.0	177	0	0	6.84	
88-02-08	Produced Fluid (flowback)	3.5	0.37	0.48	0.130	3.90	0.023	380	131.0	0.63	21.2	376	191.0	181	0	0	8.11	44
88-02-10	Produced Fluid (flowback)	4.2	0.22	1.10	0.087	5.20	0.026	430	143.0	0.60	27.5	497	230.0	172	0	0	7.86	50
88-02-20	Produced Fluid (pumping)																	50
88-02-26	Produced Fluid (pumping)	8.7	0.27	0.07	0.017	13.80	0.058	500	145.0	0.42	58.1	639	255.0	118	0	0	7.80	163
88-03-04	Produced Fluid (pumping)	7.0	0.29	0.09	0.016	23.0	0.043	490	135.0	0.86	30.0	454	254.0	260	0	0	7.84	284
88-03-12	Produced Fluid (pumping)	4.5	0.21	0.06	0.014	26.4	0.033	480	108.0	0.81	26.4	460	23.6	316	0	0	8.21	387
88-03-22	Produced Fluid (pumping)	13.5	2.80	0.24	0.031	29.4	0.420	745	51.5	0.42	47.4	439	75.8	1130	145.0	0	8.92	
88-03-26	Produced Fluid (pumping)	11.2	1.70	0.08	0.030	31.8	0.470	750	50.0	0.12	44.0	441	48.8	1240	91.7	0	8.71	65
88-03-28	produced Fluid (pumping)																	94
88-04-08	Produced Fluid (pumping)	8.8	2.2	0.26	0.021	27.2	0.45	820	36.4	0.09	38.6	489	55.2	1295	27.5	0	8.38	50
88-04-24	Produced Fluid (pumping)	6.8	1.4	0.06	0.019	27.2	0.39	870	40.6	0.35	38.6	477	28.1	1389	38.6	0	8.37	50
88-05-04	Produced Fluid (pumping)	4.3	1.0	0.06	0.010	22.2	0.21	838	30.0	0.15	38.8	449	32.6	1474	0	0	8.35	50
88-05-28	Produced Fluid (pumping)	3.9	1.2	<0.01	0.008	22.0	0.28	837	30.7	0.08	37.8	485	12.9	1391	0	0	7.52	50

TABLE 21

WATER ANALYSIS - WELL 08-04-81-22 W4M (NON ADDITIVE)

Date	Sample Description	Ion Concentration (mg/l)																Surf. Concen.
		Ca	Mg	Fe	Mn	B	Sr	Na	Si	Al	K	Cl	SO4	HCO3	CO3	OH	pH	(mg/l)
87-12-10	Produced Fluid (flowback)	1.9	0.60	3.43	0.099	0.6	0.007	73	91.8	1.20	3.77	55.9	74.2	3	0	0	7.43	
87-12-11	Produced Fluid (flowback)	1.5	0.26	0.26	0.042	0.8	0.007	30	84.3	1.28	1.90	12.7	12.6	34	0	0	7.36	
87-12-13	Produced Fluid (flowback)	1.9	0.25	0.37	0.019	5.9	0.007	140	160.0	1.23	11.10	160.0	105.0	59	0	0	7.43	
87-12-27	Produced Fluid (pumping)	5.2	0.64	1.07	0.047	11.0	0.035	308	138.0	0.48	44.10	312.0	114.0	218	0	0	7.75	
88-01-03	Produced Fluid (pumping)	2.6	0.94	0.09	0.012	17.5	0.024	350	103.0	0.54	35.9	308.0	109.0	370	0	0	8.17	
88-01-14	Produced Fluid (pumping)	4.2	1.31	<0.01	0.007	21.0	0.090	630	69.3	0.58	95.4	380.0	89.2	1030	0	0	8.27	
88-01-22	Produced Fluid (pumping)	5.0	1.53	<0.01	<0.004	23.2	0.150	686	53.3	0.33	45.2	376.0	73.6	1040	62.7	0	8.65	
88-01-29	Produced Fluid (pumping)	13.1	3.00	0.16	0.035	21.8	0.190	700	44.5	0.35	43.5	410.0	80.7	1020	82.0	0	8.76	
88-03-06	Produced Fluid (pumping)	9.9	1.70	0.02	0.034	29.7	0.420	800	28.2	0.08	62.6	529.0	267.0	1280	26.5	0	8.43	<10
88-03-18	Produced Fluid (pumping)	5.7	1.70	0.05	0.015	28.0	0.450	938	23.0	0.13	50.0	593.0	46.2	1474	24.1	0	8.37	<10

ATTACHMENT 1

E.M.R. SAMPLING AND SCHEDULE COLLECTION

For each EMR well, samples will be taken during the following stages:

1. Before Steamings: (Samples #1.1 and 1.2)

   Four 1L samples of fluid taken within one week before steaming on two different days (4L each of the two days).

   Put the samples into brown containers. The samples to be sent to Alberta Research Council (ARC) - Edmonton.

2. During The Steaming Period: (Samples #2.1, 2.2, 2.3, 2.4 and 2.5)

   Sample #2.1 Two 1L of source water taken during the entire EMR program
   #2.2 only once from Sections 3 and 4 and once from Sections 16 and 17.

   Put the samples into white containers. Samples to be sent to Lois McCorriston (Calgary).

   Sample #2.3 Two 1L boiler effluent (condensate) samples, taken on day 2
   #2.4 and day 9 of steaming. The boiler effluent sample should be taken from the steam quality pot/trap to correctly obtain the high pH liquid phase of the steam.

   Put the samples into white containers. Samples to be sent to Lois McCorriston (Calgary).

   Sample #2.5 1L pre wash 1% KCl water. Put the samples into white containers. Samples to be sent to Loid McCorriston (Calgary).

3. During Flowing Back Period: (Samples #3.1, 3.2 ...)

A. Sample #3.1 Four 1L samples (if water only) or
   #3.2 Eight 1L samples (if oil and water)
   #3.3 taken during the first day
   #3.4 each 6 hours (Two 1L samples at the time).

Put the water only samples into white containers and send them to Lois McCorriston (Calgary). Put the oil and water samples into brown containers and send 1L to ARC - Edmonton and 1L to Lois McCorriston - Calgary.

B. Samples #3.5 One 1L sample per day (if water only) or
#3.6 Two 1L samples per day (if oil and water)
(depends on number of days flowing).

Put the water only samples into white containers and send them to Lois McCorriston (Calgary). Put the oil and water samples into brown containers and send 1L to ARC - Edmonton and 1L to Lois McCorriston.

4. <u>During Production Period (Well on Pump):</u> (Samples #4.1, 4.2 ...)

At least 2 wellhead cuts will be taken per day until the water flow subsides and fluid cuts stabilize.

A.	Samples #4.1	Two 1L samples taken once	)
	#4.2	a day for the first 15 days	) 1st month of
	#4.3		) production
	#4.4		)
	#4.5		)
	#4.6		)
	#4.7		)
	#4.8		)
	#4.9		)
	#4.10		)
	#4.11		)
	#4.12		)
	#4.13		)
	#4.14		)
	#4.15		)
B.	Samples #4.16	Two 1L samples taken every	)
	#4.17	2 days for the next 15 days	)
	#4.18		)
	#4.19		)
	#4.20		)
	#4.21		)
	#4.22		)
	$4.23		)
C.	Samples #4.24	Two 1L samples taken once	
	#4.25	a week for the subsequent	
	.	period of production until the	
	.	well is back to "primary" production.	
	.	(depends on number of weeks on production	
	.	until the wells achieve 3 m^3 oil/day).	

ATTACHMENT 2A

Samples taken from Well 7-17-81-22W4

SAMPLE NO.	DATE	DAYS ON PROD.	SAMPLE ORIGIN	SAMPLE DESCRIPTION
1	30-Sep	---	Steam Gen.	steam condensate - Day 3
2	10-Oct	---	Steam Gen.	steam condensate - Day 13
3		---		1% KCl preflush
4	15-Oct	---	wellhead	flowback fluid - start
5	15-Oct	---	wellhead	flowback fluid - 6 hrs.
6	15-Oct	---	wellhead	flowback fluid - 12 hrs.
7	16-Oct	---	wellhead	flowback fluid - 18 hrs.
8	16-Oct	---	wellhead	flowback fluid - 24 hrs.
9	20-Oct	1	wellhead	produced fluid
10	23-Oct	2	wellhead	produced fluid
11	24-Oct	3	wellhead	produced fluid
12	25-Oct	4	wellhead	produced fluid
13	26-Oct	5	wellhead	produced fluid
14	27-Oct	6	wellhead	produced fluid
15	28-Oct	7	wellhead	produced fluid
16	29-Oct	8	wellhead	produced fluid
17	30-Oct	9	wellhead	produced fluid
18	01-Nov	10	wellhead	produced fluid
19	02-Nov	11	wellhead	produced fluid
20	03-Nov	12	wellhead	produced fluid
21	05-Nov	14	wellhead	produced fluid
22	06-Nov	15	wellhead	produced fluid
23	08-Nov	17	wellhead	produced fluid
24	12-Nov	21	wellhead	produced fluid
25	14-Nov	23	wellhead	produced fluid
26	16-Nov	25	wellhead	produced fluid
27	18-Nov	27	wellhead	produced fluid
28	20-Nov	29	wellhead	produced fluid
29	29-Nov	37	wellhead	produced fluid
30	08-Dec	46	wellhead	produced fluid
31	15-Dec	53	wellhead	produced fluid
32	22-Dec	59	wellhead	produced fluid
33	29-Dec	66	wellhead	produced fluid
34	05-Jan	73	wellhead	produced fluid
35	12-Jan	80	wellhead	produced fluid
36	19-Jan	87	wellhead	produced fluid
37	09-Feb	99	wellhead	produced fluid
38	23-Feb	122	wellhead	produced fluid

Samples taken from Well 9-17-81-22W4

SAMPLE NO.	DATE	DAYS ON PROD.	SAMPLE ORIGIN	SAMPLE DESCRIPTION
1	24-Aug	---	wellhead	prod. fluid - pre-steam
2	01-Sep	---	Steam Gen.	steam condensate - Day 2
3	07-Sep	---	Steam Gen.	steam condensate - Day 9
4	25-Aug	---		1% KCl preflush
5	12-Sep	---	wellhead	flowback fluid - 6 hrs.
6	13-Sep	---	wellhead	flowback fluid - 12 hrs.
7	16-Sep	1	wellhead	produced fluid
8	17-Sep	2	wellhead	produced fluid
9	18-Sep	3	wellhead	produced fluid
10	19-Sep	4	wellhead	produced fluid
11	20-Sep	5	wellhead	produced fluid
12	21-Sep	6	wellhead	produced fluid
13	22-Sep	7	wellhead	produced fluid
14	23-Sep	8	wellhead	produced fluid
15	24-Sep	9	wellhead	produced fluid
16	25-Sep	10	wellhead	produced fluid
17	26-Sep	11	wellhead	produced fluid
18	27-Sep	12	wellhead	produced fluid
19	28-Sep	13	wellhead	produced fluid
20	29-Sep	14	wellhead	produced fluid
21	30-Sep	15	wellhead	produced fluid
22	02-Oct	17	wellhead	produced fluid
23	04-Oct	19	wellhead	produced fluid
24	06-Oct	21	wellhead	produced fluid
25	08-Oct	23	wellhead	produced fluid
26	10-Oct	25	wellhead	produced fluid
27	12-Oct	27	wellhead	produced fluid
28	14-Oct	29	wellhead	produced fluid
29	23-Oct	38	wellhead	produced fluid
30	30-Oct	45	wellhead	produced fluid
31	06-Nov	52	wellhead	produced fluid
32	20-Nov	66	wellhead	produced fluid
33	27-Nov	73	wellhead	produced fluid
34	04-Dec	80	wellhead	produced fluid
35	16-Sep	101	wellhead	produced fluid
36	01-Jan	108	wellhead	produced fluid
37	08-Jan	115	wellhead	produced fluid
38	15-Jan	122	wellhead	produced fluid
39	29-Jan	136	wellhead	produced fluid

ATTACHMENT 2C

Samples taken from Well 10-17-81-22W4

SAMPLE NO.	DATE	DAYS ON PROD.	SAMPLE ORIGIN	SAMPLE DESCRIPTION
1	11-Sep	---	wellhead	prod. fluid - pre-steam
2	13-Sep	---	wellhead	prod. fluid - pre-steam
3		---	Steam Gen.	steam condensate - Day 7
4		---	Steam Gen.	steam condensate - Day 9
5		---		1% KCl preflush
6	29-Sep	---	wellhead	flowback fluid - start
7	29-Sep	---	wellhead	flowback fluid - 6 hrs.
8	29-Sep	---	wellhead	flowback fluid - 12 hrs.
9	30-Sep	---	wellhead	flowback fluid - 18 hrs.
10	30-Sep	---	wellhead	flowback fluid - 27 hrs.
11	03-Oct	1	wellhead	produced fluid
12	04-Oct	2	wellhead	produced fluid
13	05-Oct	3	wellhead	produced fluid
14	06-Oct	4	wellhead	produced fluid
15	07-Oct	5	wellhead	produced fluid
16	08-Oct	6	wellhead	produced fluid
17	09-Oct	7	wellhead	produced fluid
18	10-Oct	8	wellhead	produced fluid
19	11-Oct	9	wellhead	produced fluid
20	12-Oct	10	wellhead	produced fluid
21	13-Oct	11	wellhead	produced fluid
22	14-Oct	12	wellhead	produced fluid
23	15-Oct	13	wellhead	produced fluid
24	17-Oct	15	wellhead	produced fluid
25	19-Oct	17	wellhead	produced fluid
26	21-Oct	19	wellhead	produced fluid
27	23-Oct	21	wellhead	produced fluid
28	25-Oct	23	wellhead	produced fluid
29	27-Oct	25	wellhead	produced fluid
30	30-Oct	27	wellhead	produced fluid
31	01-Nov	29	wellhead	produced fluid
32	08-Nov	36	wellhead	produced fluid
33	15-Nov	43	wellhead	produced fluid
34	22-Nov	49	wellhead	produced fluid
35	29-Nov	56	wellhead	produced fluid
36	06-Dec	63	wellhead	produced fluid
37	14-Dec	71	wellhead	produced fluid
38	27-Dec	78	wellhead	produced fluid
39	03-Jan	91	wellhead	produced fluid
40	10-Jan	98	wellhead	produced fluid

Samples taken from Well 15-17-81-22W4

SAMPLE NO.	DATE	DAYS ON PROD.	SAMPLE ORIGIN	SAMPLE DESCRIPTION
1	04-Aug	---	wellhead	prod. fluid - pre-steam
2	14-Aug	---	Borrow Pit@Sec 17	source H2O for steam gen.
3	14-Aug	---	Steam Gen.	steam condensate - Day 2
4	22-Aug	---	Steam Gen.	steam condensate - Day 9
5	11-Aug	---		1% KCl preflush
6	26-Aug	---	wellhead	flowback fluid - start
7	26-Aug	---	wellhead	flowback fluid - 6 hrs.
8	27-Aug	---	wellhead	flowback fluid - 18 hrs.
9	27-Aug	---	wellhead	flowback fluid - 24 hrs.
10	27-Aug	---	wellhead	flowback fluid - 36 hrs.
11	31-Aug	1	wellhead	produced fluid
12	01-Sep	2	wellhead	produced fluid
13	02-Sep	3	wellhead	produced fluid
14	03-Sep	4	wellhead	produced fluid
15	04-Sep	5	wellhead	produced fluid
16	05-Sep	6	wellhead	produced fluid
17	06-Sep	7	wellhead	produced fluid
18	07-Sep	8	wellhead	produced fluid
19	08-Sep	9	wellhead	produced fluid
20	09-Sep	10	wellhead	produced fluid
21	10-Sep	11	wellhead	produced fluid
22	11-Sep	12	wellhead	produced fluid
23	12-Sep	13	wellhead	produced fluid
24	13-Sep	14	wellhead	produced fluid
25	14-Sep	15	wellhead	produced fluid
26	16-Sep	17	wellhead	produced fluid
27	18-Sep	19	wellhead	produced fluid
28	20-Sep	21	wellhead	produced fluid
29	22-Sep	23	wellhead	produced fluid
30	24-Sep	25	wellhead	produced fluid
31	26-Sep	27	wellhead	produced fluid
32	28-Sep	29	wellhead	produced fluid
33	30-Sep	31	wellhead	produced fluid
34	07-Oct	38	wellhead	produced fluid
35	14-Oct	45	wellhead	produced fluid
36	30-Oct	59	wellhead	produced fluid
37	20-Nov	78	wellhead	produced fluid
38	27-Nov	85	wellhead	produced fluid
39	04-Dec	91	wellhead	produced fluid
40	18-Dec	105	wellhead	produced fluid
41	25-Dec	112	wellhead	produced fluid
42	15-Jan	126	wellhead	produced fluid
43	29-Jan	140	wellhead	produced fluid

ATTACHMENT 2E

Samples taken from Well 5A-3-81-22W4

SAMPLE NO.	DATE	DAYS ON PROD.	SAMPLE ORIGIN	SAMPLE DESCRIPTION
1	27-Dec	---	Steam Gen.	steam condensate - Day 2
2	01-Jan	---	Steam Gen.	steam condensate - Day 9
3	03-Jan	---	wellhead	flowback fluid - Day 3
4	04-Jan	---	wellhead	flowback fluid - Day 4
5	05-Jan	---	wellhead	flowback fluid - Day 5
6	06-Jan	---	wellhead	flowback fluid - Day 6
7	07-Jan	---	wellhead	flowback fluid - Day 7
8	20-Jan	4	wellhead	produced fluid
9	21-Jan	5	wellhead	produced fluid
10	22-Jan	6	wellhead	produced fluid
11	23-Jan	7	wellhead	produced fluid
12	24-Jan	8	wellhead	produced fluid
13	25-Jan	9	wellhead	produced fluid
14	26-Jan	10	wellhead	produced fluid
15	27-Jan	11	wellhead	produced fluid
16	28-Jan	12	wellhead	produced fluid
17	29-Jan	13	wellhead	produced fluid
18	30-Jan	14	wellhead	produced fluid
19	19-Feb	24	wellhead	produced fluid
20	21-Feb	26	wellhead	produced fluid
21	23-Feb	28	wellhead	produced fluid
22	25-Feb	30	wellhead	produced fluid
23	27-Feb	32	wellhead	produced fluid
24	29-Feb	34	wellhead	produced fluid
25	03-Mar	37	wellhead	produced fluid
26	07-Mar	41	wellhead	produced fluid
27	14-Mar	48	wellhead	produced fluid
28	21-Mar	55	wellhead	produced fluid
29	04-Apr	62	wellhead	produced fluid
30	18-Apr	76	wellhead	produced fluid
31	07-May	88	wellhead	produced fluid
32	15-May	96	wellhead	produced fluid
33	21-May	102	wellhead	produced fluid
34	28-May	109	wellhead	produced fluid
35	11-Jun	123	wellhead	produced fluid
36	18-Jun	130	wellhead	produced fluid
37	09-Jul		wellhead	produced fluid

Samples taken from Well 8A-4-81-22W4

SAMPLE NO.	DATE	DAYS ON PROD.	SAMPLE ORIGIN	SAMPLE DESCRIPTION
1	31-Oct	---	Steam Gen.	steam condensate - Day 2
2	16-Nov	---	Steam Gen.	steam condensate - Day 9
3	23-Nov	---	wellhead	flowback fluid - start
4	23-Nov	---	wellhead	flowback fluid - 6 hrs.
5	23-Nov	---	wellhead	flowback fluid - 12 hrs.
6	23-Nov	---	wellhead	flowback fluid - 18 hrs.
7	24-Nov	---	wellhead	flowback fluid - 24 hrs.
8	24-Nov	---	wellhead	flowback fluid - 39 hrs.
9	30-Nov	4	wellhead	produced fluid
10	01-Dec	5	wellhead	produced fluid
11	02-Dec	6	wellhead	produced fluid
12	03-Dec	7	wellhead	produced fluid
13	04-Dec	8	wellhead	produced fluid
14	05-Dec	9	wellhead	produced fluid
15	06-Dec	10	wellhead	produced fluid
16	07-Dec	11	wellhead	produced fluid
17	08-Dec	12	wellhead	produced fluid
18	09-Dec	13	wellhead	produced fluid
19	10-Dec	14	wellhead	produced fluid
20	11-Dec	15	wellhead	produced fluid
21	12-Dec	16	wellhead	produced fluid
22	13-Dec	17	wellhead	produced fluid
23	14-Dec	18	wellhead	produced fluid
24	16-Dec	20	wellhead	produced fluid
25	19-Dec	23	wellhead	produced fluid
26	22-Dec	26	wellhead	produced fluid
27	24-Dec	28	wellhead	produced fluid
28	26-Dec	30	wellhead	produced fluid
29	28-Dec	32	wellhead	produced fluid
30	02-Jan	35	wellhead	produced fluid
31	09-Jan	41	wellhead	produced fluid
32	23-Jan	54	wellhead	produced fluid
33	30-Jan	61	wellhead	produced fluid
34	20-Feb	80	wellhead	produced fluid
35	27-Feb	87	wellhead	produced fluid
36	05-Mar	94	wellhead	produced fluid
37	12-Mar	101	wellhead	produced fluid
38	26-Mar	115	wellhead	produced fluid
39	02-Apr	122	wellhead	produced fluid
40	09-Apr	129	wellhead	produced fluid

ATTACHMENT 2G

Samples taken from Well 12-3-81-22W4

SAMPLE NO.	DATE	DAYS ON PROD.	SAMPLE ORIGIN	SAMPLE DESCRIPTION
1	07-Jan	---	Steam Gen.	steam condensate - Day 3
2	28-Jan	---	Steam Gen.	steam condensate - Day 23
3	03-Feb	---	wellhead	flowback fluid - start
4	04-Feb	---	wellhead	flowback fluid - 6 hrs.
5	04-Feb	---	wellhead	flowback fluid - 12 hrs.
6	04-Feb	---	wellhead	flowback fluid - 18 hrs.
7	05-Feb	---	wellhead	flowback fluid - Day 2
8	06-Feb	---	wellhead	flowback fluid - Day 3
9	07-Feb	---	wellhead	flowback fluid - Day 4
10	08-Feb	---	wellhead	flowback fluid - Day 5
11	09-Feb	---	wellhead	flowback fluid - Day 6
12	10-Feb	---	wellhead	flowback fluid - Day 7
13	20-Feb	6	wellhead	produced fluid
14	22-Feb	8	wellhead	produced fluid
15	24-Feb	10	wellhead	produced fluid
16	26-Feb	12	wellhead	produced fluid
17	28-Feb	14	wellhead	produced fluid
18	01-Mar	16	wellhead	produced fluid
19	03-Mar	18	wellhead	produced fluid
20	04-Mar	19	wellhead	produced fluid
21	06-Mar	21	wellhead	produced fluid
22	08-Mar	23	wellhead	produced fluid
23	10-Mar	25	wellhead	produced fluid
24	12-Mar	27	wellhead	produced fluid
25	14-Mar	29	wellhead	produced fluid
26	16-Mar	31	wellhead	produced fluid
27	22-Mar	37	wellhead	produced fluid
28	24-Mar	39	wellhead	produced fluid
29	26-Mar	41	wellhead	produced fluid
30	28-Mar	43	wellhead	produced fluid
31	30-Mar	45	wellhead	produced fluid
32	08-Apr	53	wellhead	produced fluid
33	16-Apr	61	wellhead	produced fluid
34	24-Apr	69	wellhead	produced fluid
35	30-Apr	75	wellhead	produced fluid
36	07-May	78	wellhead	produced fluid
37	14-May	85	wellhead	produced fluid
38	21-May	92	wellhead	produced fluid
39	28-May	99	wellhead	produced fluid
40	11-Jun	113	wellhead	produced fluid
41	18-Jun	120	wellhead	produced fluid
42	25-Jun	127	wellhead	produced fluid
43	09-Jul	141	wellhead	produced fluid

Samples taken from Well 8-4-81-22W4

SAMPLE NO.	DATE	DAYS ON PROD.	SAMPLE ORIGIN	SAMPLE DESCRIPTION
1	06-Dec	---	Borrow Pit - Pilot	source H2O for steam gen.
2	06-Dec	---	Steam Gen.	steam condensate - Day 9
3	10-Dec	---	wellhead	flowback fluid - 6 hrs.
4	11-Dec	---	wellhead	flowback fluid - 12 hrs.
5	11-Dec	---	wellhead	flowback fluid - 18 hrs.
6	11-Dec	---	wellhead	flowback fluid - 24 hrs.
7	12-Dec	---	wellhead	flowback fluid - Day 2
8	13-Dec	---	wellhead	flowback fluid - Day 3
9	23-Dec	2	wellhead	produced fluid
10	24-Dec	3	wellhead	produced fluid
11	25-Dec	4	wellhead	produced fluid
12	26-Dec	5	wellhead	produced fluid
13	27-Dec	6	wellhead	produced fluid
14	29-Dec	8	wellhead	produced fluid
15	30-Dec	9	wellhead	produced fluid
16	31-Dec	10	wellhead	produced fluid
17	01-Jan	11	wellhead	produced fluid
18	03-Jan	13	wellhead	produced fluid
19	04-Jan	14	wellhead	produced fluid
20	08-Jan	18	wellhead	produced fluid
21	10-Jan	20	wellhead	produced fluid
22	12-Jan	22	wellhead	produced fluid
23	14-Jan	24	wellhead	produced fluid
24	22-Jan	32	wellhead	produced fluid
25	29-Jan	39	wellhead	produced fluid
26	28-Feb	65	wellhead	produced fluid
27	06-Mar	72	wellhead	produced fluid
28	11-Mar	77	wellhead	produced fluid
29	18-Mar	84	wellhead	produced fluid
30	01-Apr	92	wellhead	produced fluid
31	08-Apr	99	wellhead	produced fluid
32	17-Apr	108	wellhead	produced fluid
33	24-Apr	115	wellhead	produced fluid
34	01-May	122	wellhead	produced fluid
35	15-May	136	wellhead	produced fluid